DOE/ET/27146--T17

# REPORT

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## REINJECTION AND INJECTION OF FLUIDS IN GEOTHERMAL OPERATIONS (STATE OF THE ART)


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SUBMITTED TO

UNITED STATES DEPARTMENT OF ENERGY

DIVISION OF GEOTHERMAL ENERGY

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## 1.0 PREAMBLE

The United States Department of Energy (DOE/DGE) awarded Vetter Research (VR) a contract to perform research and development work related to injection and reinjection problems in geothermal operations. This contract (NO. DE-AC03-79ET-27146) is entitled: "Injection, Injectivity and Injectability in Geothermal Operations". In this present and final report on contract No. DE-AC03-79ET-27146, an attempt is made to describe the various parts of the contractual study (a) in the form of an overview and (b) to high-light the more important findings and conclusions. This present and final report gives an overview of the study aimed at (a) defining and describing the problems of geothermal fluid injections and (b) finding and/or suggesting some solutions to the encountered and defined problems. Because of the still fledgling nature of the geothermal industry at this time, some of the details given in this report will be subject to revisions as the industry and its technology progresses. Therefore, heavy emphasis is placed on the role of reinjection and reinjection operations as a key and integral part of an overall geothermal field operation.

## 2.0 CONTRACTUAL WORK FOR U.S. DOE/DGE

Between 1970 and 1980, ERDA and later the U.S. Department of Energy/Division of Geothermal Energy (DOE/DGE) realized numerous problems related to the reinjection of heat-depleted geothermal brines. VR was awarded a two year contract to define these problems. Then, a rather complex laboratory and theoretical study was started to evaluate the problems in more detail and to investigate possible or potentially valid solutions to these problems. This work was complemented by numerous field tests.

During the life of the contract, numerous new technical problems were encountered. Many of these new problems were not anticipated when the contract was started in 1979. All technical problems encountered during this contract were outlined in previous reports [1 through 25].

The following table gives the titles and issuing dates of the previous reports under this contract:

| REFERENCE | TITLE OF REPORT |
|---|---|
| [1] | INJECTION, INJECTIVITY AND INJECTABILITY IN GEOTHERMAL OPERATIONS: PROBLEMS AND POSSIBLE SOLUTIONS. PHASE I-DEFININITION OF THE PROBLEM, FEBRUARY 1979 (VR REPORT NO. 790214). |
| [2] | GRAND SCHEME FOR THE GEOTHERMAL INDUSTRY IN THE IMPERIAL VALLEY. OCT.8,1979 (VR REPORT NO.791008). |

[3] INJECTION, INJECTIVITY AND INJECTABILITY IN GEOTHERMAL OPERATIONS-MANAGEMENT,COST AND MANPOWER PLAN. DEC.5,1979 (VR REPORT NO. 791205).

[4] INTEGRATED GEOTHERMAL WELL TESTING PART II B: TEST EXPERIENCES AT MAPCO`S CURRIER 2-FLOW DATA SECTION 1. SEPT.5, 1980 (VR REPORT NO. 800905).

[5] INTEGRATED GEOTHERMAL WELL TESTING PART II B: TEST EXPERIENCES AT MAPCO`S CURRIER 2-FLOW DATA SECTION 2. SEPT.6,1980 (VR REPORT NO.800906).

[6] INTEGRATED GEOTHERMAL WELL TESTING; PART II B: TEST EXPERIENCES AT MAPCO`S CURRIER 2-FLOW DATA SECTION 3. SEPT.7, 1980 (VR REPORT NO. 800907).

[7] INTEGRATED GEOTHERMAL WELL TESTING MAPCO`S PART II B: TEST EXPERIENCES AT CURRIER 2-FLOW DATA SECTION 4. SEPT.8, 1980 (VR REPORT NO. 800908).

[8] INTEGRATED GEOTHERMAL WELL TESTING PART II B:TEST EXPERIENCES AT MAPCO`S CURRIER 2-CHEMICAL DATA. SEPT.9, 1980 (VR REPORT NO. 800909).

[9] INTEGRATED GEOTHERMAL WELL TESTING PART II A: TEST EXPERIENCES AT MAPCO`S CURRIER 2-GENERAL PART. NOV.3, 1980 (VR REPORT NO. 801103).

[10] PARTICLE CHARACTERIZATION IN GEOTHERMAL OPERATIONS. JAN.6, 1981 (VR REPORT NO. 810106).

[11] FOREIGN WATER INJECTION INTO GEOTHERMAL RESERVOIRS (CHEMICAL COMPATIBILITY PROBLEMS). JUNE 15, 1981 (VR REPORT NO.810615).

[12] PARTICLE CHARACTERIZATION FOR GEOTHERMAL OPERATIONS: PART 2:FIELD EXPERIENCES. NOV.11, 1981 (VR REPORT NO. 811111).

[13] INTEGRATED GEOTHERMAL WELL TESTING: PART 1: TEST FACILITIES PROGRAMS AND OPERATIONS. FEBRUARY 14, 1982 (VR REPORT NO. 820224).

[14] INTEGRATED GEOTHERMAL WELL TESTING: PART III: TEST EXPERIENCES AT MCR`S MERCER 2. MARCH 2, 1982 (VR REPORT NO.820322).

[15] SOME THOUGHTS ON THE VALUE AND PRESENT STATUS OF SCALE PREDICTION MODELS FOR GEOTHERMAL OPERATIONS. MARCH 22, 1982 (VR REPORT NO. 820322).

[16] SCALE INHIBITOR EVALUATION FOR APPLICATION TO REINJECTION OPERATIONS. MARCH 29, 1982 (VR REPORT NO.820329).

[17] IN-LINE INSTRUMENTATION IN GEOTHERMAL OPERATIONS. APRIL, 1982 (VR REPORT NO. 820402).

[18] HANDLING AND REINJECTION OF NON-CONDENSABLE GASES IN GEOTHERMAL OPERATIONS, APRIL 22, 1982 (VR REPORT NO. 820429).

[19] FLOW OF PARTICLE SUSPENSIONS THROUGH POROUS MEDIA. JUNE 22, 1982. (VR REPORT NO. 820622).

[20] SCALE FORMATION AT VARIOUS LOCATIONS IN A GEOTHERMAL OPERATION DUE TO INJECTION OF IMPORTED WATERS, JUNE 22, 1982. (VR REPORT NO. 820622).

[21] RADIOLABELLING OF CHEMICALS, JUNE 22, 1982 (VR REPORT NO. 820622).

[22] CHEMICAL DAMAGE DUE TO DRILLING OPERATIONS, JUNE 14, 1982, (VR REPORT NO. 820714).

[23] CHEMICAL STIMULATION OF GEOTHERMAL INJECTION WELLS, JUNE 23, 1982, (VR REPORT NO. 820623).

[24] ENHANCEMENT OF HEAT PRODUCTION THROUGH SELECTIVE SCALING, AUGUST 16, 1982, (VR REPORT NO. 820816).

[25] CHEMICAL DAMAGE DUE TO FLOCCULANT INJECTION, AUGUST 17, 1982, (VR REPORT NO. 820817).

[26] REINJECTION AND INJECTION OF FLUIDS IN GEOTHERMAL OPERATIONS-STATE OF THE ART

VR Report No. 26 (see table above) is the present and final report under this contract.

To aid in the dissemination of the more pertinent information into the public domain, a number of publications were written and submitted to various professional societies and magazines. The following table gives the publications precipitated in one or another form based upon the work performed under this contract:

| REFER. OF PUBLICATION | TITLE OF PUBLICATION | JOURNAL OR CONFERENCE |
|---|---|---|
| [27] | NON-CONDENSABLES IN GEOTHERMAL OPERATIONS | SPE |
| [28] | RADIOACTIVE TRACER ADSORPTION CHROMATOGRAPHY IN GEOTHERMAL RESERVOIRS | SPE |
| [29] | INJECTION, INJECTIVITY AND INJECTABILITY IN GEOTHERMAL OPERATIONS | GRC |
| [30] | AN INTEGRATED APPROACH TO GEOTHERMAL WELL TESTING | GRC |
| [31] | THE ROLE OF STANDARDS IN GEOTHERMAL SAMPLING | ASTM |
| [32] | PREDICTION OF CaCO3 SCALE UNDER DOWNHOLE CONDITIONS | SPE |
| [33] | SUSPENDED SOLIDS REMOVAL PRIOR TO BRINE REINJECTION | GRC |
| [34] | SCALE INHIBITION FOR INJECTION OF INCOMPATIBLE WATERS | SPE |
| [35] | HANDLING OF SCALE IN GEOTHERMAL OPERATIONS | INT`L CONF. ON GEOTHERMAL ENERGY, FLORENCE, ITALY, 1982 |
| [36] | ASSESSMENT OF THE CHARACTERIZATION (IN-SITU DOWNHOLE) OF GEOTHERMAL BRINES | NAT`L ACADEMY OF SCIENCE |
| [37] | PREDICTION OF SALT PRECIPITATIONS DUE TO INJECTING FOREIGN WATERS INTO GEOTHERMAL RESERVOIRS | GRC |
| [38] | EVALUATION OF GEOTHERMAL BRINE TREATMENT FACILITY THROUGH PARTICLE CHARACTERIZATION | GRC |

| | | |
|---|---|---|
| [39] | A NEW APPROACH TO GEOTHERMAL PRODUCTION TESTING: RECENT EXPERIENCES IN THE USA AND ITALY | INT`L CONF.ON GEOTHERMAL ENERGY, FLORENCE,ITALY, 1982 |
| [40] | A USEFUL TECHNIQUE TO STUDY PARTICLE INVASION INTO POROUS MEDIA BY BACKSCATTERED ELECTRON IMAGING | SPE |

A number of topics covered under this contract are still awaiting their publication at conferences or in technical journals. It is estimated that at least five more publications will result from this work. Based upon this performance record, we can safely state that this contract and the associated work represents a success for both DOE/DGE and VR.

## 3.0 ABSTRACT

The present report is a summary of the problems (encountered as well as anticipated) associated with reinjection of heat-depleted brines and injection of other fluids such as imported brines and gases. Covered in this report are only injection and reinjection problems which are related to the exploitation of liquid-dominated resources by flash-cycle power plants. The report also covers suggestions (proven as well as probable) which may offer solutions to many of the identified problems. In addition, the report also describes some ideas that should or could be implemented in planning of implementing and/or executing any new geothermal injection operation. This report is intended to serve as a general guideline for any geothermal operator who is planning a new reinjection or injection operation.

There are many sources, starting from the initial drilling of injection wells through the production and subsequent injection operations that directly affect the injectivity of fluids in geothermal operations. Any of the materials entering the wellbore of a geothermal injection well at any time during its existence can cause severe and costly damage to the injection and reinjection well (i.e., a decrease of the well injectivity). These materials may enter an injection well during:

1. Drilling and completing of the well.

2. Routine reinjection of heat-depleted brines or gases produced and/or generated within the geothermal field operations.

3. Injection of imported brines (a) to maintain reservoir pressure or (b) to achieve heat-mining.

4. Utilization of the injection wells for the disposal of fluids from the geothermal operation itself or from any

outside source. This would include injection of materials to comply with environmental standards, rules or regulations.

5. Injection of fluids used to stimulate an injection or reinjection well.

The potential damage of a reinjection or injection well by long-term or intermittent injection of fluids can not only be caused by the fluids themselves but also by various chemical additives used in these fluids for various purposes.

All damages are caused by unwanted or undesired and, quite often, unkown physical and chemical reactions between injected fluids and the native reservoir materials. An understanding of the nature of the problems created by the above sources is important prior to the design or implementation of any injection operation.

The damage resulting during drilling and completion operations are such that they reduce the effective permeability of the reservoir rock (or the fracture conductivity) or plug up the wellbore. In other words, the damage resulted in these operations can make the initial injectivity of the wells considerably less than if there were no damage. The basis of the various types of damages that can result from various field operations is discussed in a fairly detailed manner in this report. Some suggestions as to the ways of reducing such damages are also given in this report. Suggestions to overcome some of the problems are also discussed.

The main obstacle to a technically and economically feasible injection and/or reinjection operation is created by the complexity of an entire geothermal field operation. Reinjection of heat-depleted fluids and injection of any other fluids are only a part of the overall field operation even though these reinjection and injection operations play a rather crucial role. Not realizing the crucial role of these operations and ignoring their function as an integral part of the overall field operations will result in heavy penalties for the operator. In other words, reinjection and/or injection problems should not be solved at the expense of a deterioration of other field operations.

The feasibiity of any design of a reinjection and injection system will depend on numerous variables. For example, the injectability of the fluids will depend on the planned or implemented brine and gas treatment facilities. On the other hand, the design and operation of these fluid treatment facilities will depend upon the reservoir characteristics of the resource and the design and operational details of the production and utilization facilities. Any change of the fluid properties upstream of the fluid treatment facilities may cause critical changes in the fluid injectability. This may easily result in a chain reaction leading to an abrupt and serious deterioration of all injection and reinjection operations. Thus, the entire field operation may come to an abrupt halt.

Therefore, in this final report and attempt is made to emphasize the role of a successful reinjection and injection operation as a critical and integral part of a rather complex overall field operation. Also pointed out is the complicating fact that even small changes of design features and operating conditions of any field facilities can have dramatic effects on the injectability of fluids and the injectivity of the wells. Thus, injection and reinjection problems should not be considered out of context and should be solved by a thorough evaluation of the effects of these solutions on the overall field operations.

## 4.0 PREVIOUS REPORTS UNDER THIS CONTRACT

Some of the previously mentioned reports (see section 2.0) have been critized by numerous readers for various reasons. The positive aspect of these frequent critisisms is the obvious indication of a serious, deep and widely spread interest in the matter. This means, DOE/DGE has chosen a topic of real concern to the industry.

The negative aspects of the previous reports under this contract [1 through 25] are numerous according to the critics:

1. It was claimed by some critics that there are too few and by others that there are too many actual data. Some reports [e.g., 4 through 8] were critized as pure "data dumps" (even though only a fraction of the accumulated data have been presented) whereas other reports (e.g., [13] and [21]) do not give sufficient data according to the same critics. Quite often, one report was attacked for giving too few data by some reviewers whereas other critics complained about too few data in the same report.

2. Others claim that there are numerous unsolved technical problems in geothermal operations which were not brought out in sufficient detail in some reports (e.g., [19]), whereas too many problems were described in too much detail in other reports (e.g., [18]).

3. According to some critics, not enough or no sufficient or acceptable solutions to the obvious problems were presented (e.g., [19],[22] and [23]).

Our general answers to these justified or unjustified criticisms are listed below:

1. The reinjection and injection of geothermal fluids must be considered as an integral part of a geothermal

operation and is much more complex than expected or anticipated by most of these critics. There is no way to describe all possible problems and their potential solutions in minute detail within the budget and timing constraints of this contract. One of our main objectives was to attack some rather simplistic geothermal reinjection and injection concepts or schemes which were prevailing in the industry and which are still considered valid by some of the critics. Some of these critics still seem to adhere to these simplistic and dangerous concepts which were proven by us and others to be wrong, i.e., technically and/or economically unfeasible for the industry.

2. The various subjects of the general topic (reinjection and injection) require many and quite different types of expertise. Many of the critics are obviously involved only in one or a limited number of subjects but are not familiar with others. Thus, any report written on "their" subjects may fall short of completeness whereas reports outside of "their" subject areas are considered far too extensive and a "waste of efforts". Obviously the reports can not equally well address all potential interests and levels of expertise of all potential readers.

3. The main objective of this contract was not to solve all injection and related problems single-handedly. The main objectives were to identify real and potential problems and to suggest potentially valid solutions. We should not be blamed for being unable to solve a "billion-dollar-problem" with a "million-dollar-budget".

4. It was also not the objective of this contract to provide blueprints and shop drawings for test or well site facilities (e.g., [13], [17] and [19]) if these facilities were built or financed not through this contract but through other sources.

5. The guidelines given or implied in the reports ([1] through [25]) should be sufficient for an experienced operator to obtain familiarity with his site-specific problems. They should also allow him to devise ways and means to overcome or at least to attack these site-specific problems. It would be impossible under the time and budget constraints of this contract to handle even a limited number of site-specific problems.

In this final report, we made an attempt to avoid some of the justified and unjustified criticisms by outlining not only the objectives of the work but also by reiterating the objectives of this report itself. Only a thorough comprehension of these two different types of objectives will allow the reader to extract the maximum benefits from this present report.

## 5.0 FORM AND OBJECTIVES OF PRESENT REPORT AND SCOPE OF WORK

The general objectives of the report and scope of work are given in this section.

### 5.1 OBJECTIVES OF THE REPORT

The management of many geothermal companies is confronted with a large set of problems. The most overwhelming problem is concerned with deciding on general concepts and a host of minute details related to an economically and technically feasible exploitation of the existing geothermal resources. This major problem is created by a presently existing pronounced lack of an integrated technology for the exploitation of these high-temperature geothermal fluids. Reinjection and injection problems make up a major part of this overall problem in the geothermal industry.

Any management of a geothermal company must decide on a general concept related to the design and execution of the reinjection and injection operations. Choosing the basically wrong (i.e., technically and/or economically unfeasible) design can lead to severe and extremely costly set-backs of an entire project. Retrofitting of the field may become prohibitively expensive and will cause financial problems. In addition, the damage to the wells caused by an interim and basically wrong reinjection concept may cause the entire project to become economically unfeasible.

An evaluation of the reasons for an early failure of geothermal companies in the Imperial Valley, California can always be traced back to the mistake of selecting technically wrong or unfeasible concepts. In most cases, these concepts were too simplistic and ignored totally the specific high-temperature behavior of the geothermal fluids. Thus, literally hundreds of millions of dollars have been lost due to the failure to realize the importance of each individual field operation as an integral part of any geothermal field operation in its entirety. In fact, human ignorance and not the lack of a technical and economical feasibility has caused countless failures in the geothermal industry.

Presently, the ignorance toward the peculiarities of a site-specific geothermal operation related to its environmental impacts seem to throw up additional hurdles and barriers. Properly designed and executed field operations (particularly, reinjection and injection operations), will allow any operator to comply with most environmental rules, regulations and laws. Reinjection and injection operations play the key role in these efforts to comply. However, to design these reinjection operations only for environmental compliance will again render many operations economically and technically unfeasible. The environmental aspects must also be viewed as an integral part of the entire field operation. A proper design should improve the economics of an entire field by utilizing the "waste" products instead of generating severe problems by actually wasting them through their release into an uncontrolled area.

Considering this history and these problems, we concluded that the main objective of this report should be geared toward the management of geothermal companies. This report should be an aid in designing the general concept of the critical reinjection and injection operations. Instead of describing a host of technical and minute details, we decided to direct the attention to the role of reinjection and injection operations as a key and integral part of any geothermal over-all operation.

This main objective of this present report is achieved assuming we can make an impact on the managements in the geothermal industry as far as their decision related to the operational over-all design of a geothermal operation is concerned. Thus, it should be clear and obvious to the reader that he should not search for all of the critical and technical details in this report. These should be found in any of the previously drafted documents [1 through 25].

At this point we would also like to point out the reason for the "peculiar" style of this report. Since the report is geared to management and decision making personnel, an attempt is made to explain general concepts and problem areas rather than minute technical details. To achieve this objective a style quite different from that suited for a purely technical report has been chosen.

## 5.2 OBJECTIVES OF THE WORK UNDER THIS CONTRACT

The main scope of work can be described as follows:

1. To summarize the various problems that one may encounter in conducting the injection and reinjection of fluids (heat-depleted and/or imported brines) in geothermal operations.

2. To suggest solutions wherever clear-cut or generally accepted solutions are available and/or seem to be rather obvious.

3. To suggest sources, methods or avenues one may want to pursue where clear-cut and obvious solutions are not available and/or can not be suggested at the present time.

4. To emphasize the role of reinjection and injection operations as both key and integral parts of a geothermal resource exploitation.

Most of the information given in the report is a result of various field experiences, theoretical and laboratory studies performed by Vetter Research. Also some well-documented studies and/or experiences of other investigators are included. The information contained in the report is presented in such a manner as to serve as a guideline in initiating and performing injection operations related to the geothermal industry. However, it should be cautioned here that due to the fledgling nature of the geothermal industry, some of the details of the methods and procedures presented in this report might be subject to revisions as the industry progresses into a more mature stage and as additional information becomes available.

The contents of the present report are restricted to the injection operations related to the exploitation of liquid-dominated geothermal resources.

In addition to describing some general aspects of a geothermal operation, the following topics should be included in this report:

1. Laboratory and theoretical studies related to the identification of potential injection problems that arise during the various stages of a geothermal operation.

2. Determining, measuring and/or monitoring of various physical and chemical properties to aid in preventing the occurance of any injection problems or, at least, to aid in planning the repairs (e.g., stimulation) if any injection problems will occur.

3. The results and experiences from two specific field studies.

4. The literature information gathered on different aspects of geothermal systems operations as they are related to injection operations.

## 6.0 INTRODUCTION AND SOME HISTORICAL BACKGROUND

The prime interest of DOE/DGE and of the relatively young geothermal industry is to harness the heat contained in many liquid-dominated reservoirs. We want to use the heat content either to produce electricity or to directly utilize the heat in homes and industrial, agricultural or any different type of facility.

No matter whether the heat is utilized for the production of electricity or direct utilization, a number of common problems exist. First, the hot brine must be produced, sometimes with great difficulty and expense. Then, the heat must be extracted. Here again, a number of problems must be overcome. Finally, the heat-depleted brine and, sometimes, other fluids (such as gases) must be reinjected, which at the present time, seems to offer the most serious problems of all.

This contractual study was aimed at defining the major obstacles for a successful reinjection of heat-depleted geothermal brines within the United States. Contrary to many overoptimistic claims, the reinjection of the heat-depleted brines will often generate some severe operational problems which are far from being solved.

A considerable number of problems related to the reinjection of heat-depleted geothermal brines and injection of other fluids cannot be solved without considering the geothermal operation as a whole. Thus, even though the present contract was concerned only with injection problems, (i.e., the injectivity of geothermal injection wells and the injectability of heat-depleted brines) some topics related to various other operations of a geothermal system are included in this report.

### 6.1 WHY INJECTION IS NEEDED TO GENERATE GEOTHERMAL POWER IN THE USA

Various studies by DOE/DGE and the private industry have shown that geothermal power generation could yield large quantities of electricity at a cost very much competitive with power generation from other resources. There should not be any doubt that geothermal power is one of the most important alternate energy sources in the United States, particularly in the near-future. Even pessimistic forecasts show that geothermal power could be produced at a cost which would make it a highly desirable product for the U.S. utility companies.

Geothermal operations are presently utilized for electric power production in a number of other countries, e.g., in Mexico, Phillipines, El Salvadore, Russia, Japan and New Zealand. These operations of liquid-dominated fields should not be confused with those of vapor-dominated "dry steam" fields (e.g., the Geysers in California and Lardarello in Italy). A number of processes using the geothermal heat from liquid-dominated fields directly are also known (e.g., Iceland and various States in the U.S.).

With this background of international success and rapid expansion, an often heard question in the United States is concerned with the fact that geothermal power production from liquid-dominated resources in other countries is fully commercialized, whereas the U.S. geothermal power production is still infantile and has no fully commercialized demonstration project. The answer to this question is complex. Economic, environmental and political conditions in other countries may allow the geothermal industry to pursue its development on guidelines which are, under no circumstances, acceptable in the USA. For example, collecting the heat-depleted brine on the surface in large lagoones (e.g., Cerro Prieto in Mexico) or releasing it into existing rivers (e.g., Wairaki in New Zealand) will preclude a number of injection problems, but will generate polluted lagoons and rivers which are environmentally unacceptable within the United States.

The non-condensable gases released directly into the atmosphere in some foreign geothermal operations would cause more than raised eyebrows in the United States. In addition, failure to reinject the heat-depleted brines into the reservoir may have a serious and detrimental impact on the longevity of the reservoirs and an associated, detrimental impact for all geothermal operations within the United States. The U.S. geothermal industry will succeed if technical problems are solved according to the economic, political and environmental realities of our society.

A possible scenario providing solutions is outlined in a previous report [2] which takes into account the technical, economic, environmental and political feasibility of an integrated geothermal operation in an environmentally sensitive area within the United States.

In the following section of the report, we will try to describe a complete concept of the geothermal power generation process with its complex and complicated side aspects. The Imperial Valley in California is used as a specific example.

### 6.2 THE IMPERIAL VALLEY AS AN EXAMPLE

Using the Imperial Valley as an example will allow us to describe in detail the existing problems in geothermal power generation and to illustrate some possible solutions to these problems. The emphasis is, of course, on the role of reinjecting the heat-depleted brine.

The Imperial Valley, California was chosen as an ideal example for illustrating nearly all geothermal problems presently existing and to be expected within the near future. Many geothermal power production problems are especially critical in the Imperial Valley because of the need for the geothermal industry and its surrounding agricultural and other industries to live with each other.

#### 6.2.1 TECHNICAL PROBLEMS

The geothermal reservoirs in the Imperial Valley:

1. Are located at depths ranging between shallow (approximately 3000 feet) to deep (approximately 13,000 feet).

2. Contain brines having an extremely large range of chemical compositions. The total dissolved solids (TDS) range from 2000 mg/l (East Mesa, North Reservoir, almost drinking water quality) to values close to 300,000 mg/l (Niland and South Brawley areas).

3. Show temperatures from very low (just above 212°F) to values far in excess of 500°F.

4. Contain gases ranging from environmentally harmless (nitrogen) through questionable (carbon dioxide) to dangerous (hydrogen sulfide).

Thus, a great variety of geothermal reservoirs are found within extremely small geographic distances (on the order of a few miles). This variety makes the Imperial Valley an ideal experimental region, but at the same time asks for a rather large set of technical solutions.

The produced brines offer almost all problems regarding various types of brine utilization processes. Scale and corrosion are only a part of these problems. Literally tens of different types of scales can be found. Depending upon the reservoir, temperature and the chosen brine production and utilization processes, four major types of scale are encountered:

1. Carbonates such as calcium and strontium carbonates.

2. Silica and other siliceous materials.

3. Heavy metal sulfides.

4. Various types of exotic chlorides.

Another serious set of problems is caused by the chemical and thermal incompatabilities of the various brines. It is not unusual in the Imperial Valley that the heat-depleted brines become chemically incompatible with the brines in the reservoir where they originated in the first place. In addition, thermal (or thermodynamic) incompatabilities of the steam from different wells (entropy problem!) are often overlooked but can and will cause serious power plant problems. One should not mix a high temperature and a low temperature wellhead brine before feeding them into the equipment used for brine utilization. Two neighboring wells in the Imperial Valley may produce brines of drastically different wellhead temperatures, thus causing thermodynamic problems for the power plant operation.

The reinjection of the heat-depleted brines generates another set of major problems. Because of the large variety of brines produced from numerous wells, the injection problems can drastically change from injection well to injection well. Recent attempts by one major operator to solve a number of reinjection problems (i.e., trying to prevent the silica formation) through maintaining high temperatures in injection wells have failed. This indicates that the injection problems not only vary with the brine itself but also with the type of utilization and reinjection processes. All these problems can conveniently be studied within the Imperial Valley.

### 6.2.2 ECONOMIC PROBLEMS

As mentioned before, the electric power could be produced at competitive prices by the geothermal industry in the Imperial Valley. Many reservoirs in the Niland, Salton Sea, North Brawley, South Brawley, Westmorland and other areas within the Imperial Valley have temperatures in excess of $450^{\circ}F$. Many wells drilled in these areas have produced in excess of 500,000 lbs/hr total mass flow. Sustained wellhead flow of 700,000 lbs/hr per well should be achievable in some areas.

Some areas like Heber and East Mesa have lower wellhead temperatures and well productivities, but still could produce enough geothermal fluid for a competitive electric power production or for any other heat utilization process.

Major problems become evident when it comes to a commercialization of the prospects. Drilling, completing and testing of each well is costly. Power plant construction requires tremendous capital outlays. The lack of technical concepts for reinjection can cause heavy financial losses through costly well work-overs and repairs. Raising the high investment capital is one of the major hurdles in developing our geothermal resources.

In addition, the utility companies normally shy away from early financial commitments. Their charter prevents them from participating in any "high risk" business and they consider the production of geothermal energy a high risk business unless the reserves are proven. These reserves can be proven only after hefty investments for drilling of a sufficient number of wells and to subsequently test the reservoirs over rather long periods of time.

The DOE/DGE recognized this situation and initiated two types of programs to alleviate the problems in the Imperial Valley:

1. Technical research and support programs to aid in solving the technical problems. Unfortunately, these programs currently are being cut drastically because of the lack of funding.

2. The loan guarantee program to provide indirectly the funding for the development of a number of prospects. It allowed some developing geothermal companies to obtain up to 75 percent loans through lending institutions. Unfortunately, this program is not expected to extend into the near future.

What is needed are additional financial incentives for (a) the geothermal industry, (b) the lending institutions and (c) a host of other industries suitable to support the geothermal industry. The general scheme outlined as part of this report may provide some of these incentives.

### 6.2.3 ENVIRONMENTAL PROBLEMS

Even though geothermal energy is normally considered "clean" energy, vast environmental problems may presently exist or may develop with time. Some of these problems are already evident. Others are not so obvious or their impacts may be underestimated. The major environmental problems could be categorized as follows:

1. Gases released into the environment.

2. Liquid carry-overs and condensations finding their way into the released effluents.

3. The danger of spills (e.g., through an uncontrollable well).

4. Solid wastes to be dumped (e.g., wastes from the discarded drilling and completion fluids).

5. Subsidence of the surface land.

6. Noise, optical and odor nuisances.

Any one of these environmental problems must be avoided under all circumstances. If any one of these dangers to the environment becomes evident or a well-publicized accident occurs in the Imperial Valley, the industry may experience a major and costly set-back. For example, a run-away well or a serious subsidence problem could have devastating effects in a farming community such as the Imperial Valley. A single environmental disaster in such a sensitive agricultural area could stop all further geothermal development in the Imperial Valley and could have severe impacts on the geothermal industry in the United States as a whole. The close proximity of the Mexican border should raise another red flag.

Another set of "environmental" problems is generated by:

1. The lack of well-defined environmental standards, laws, rules and regulations with which both the industry and

environmentally oriented organizations can live.

2. The lack of internal consistency of existing laws, rules and regulations followed or adopted by the various legal authorities.

Even though the geothermal industry is presently fully occupied with solving its technical and economical problems, these environmental aspects deserve our full attention from the beginning of any field development because there is no room for errors, particularly not in the Imperial Valley.

#### 6.2.4 POLITICAL PROBLEMS

It would be redundant to outline the advantages of a functioning geothermal industry for our present society. The present energy crisis with all its detrimental implications should be recognized by any responsible person. However, the geothermal industry is fighting some fairly unnecessary battles which can seriously delay the production of electricity or other energy and material utilizations from the proven geothermal resources.

The geothermal industry is still considered an intruder in farming communities (e.g., the Imperial Valley). The "general opinion" is that geothermal energy is marvelous and is desperately needed if it is produced somewhere else. On the other hand, recently published surveys show that 25% of the working force in these areas is without a job (e.g., in the Imperial Valley). The geothermal industry should be recognized as an important instrument to solve this problem. In addition, other political problems in some of these areas are due to the facts that (a) the agricultural industry often suffers from serious water shortages, (b) the Salton Sea is becoming the "sink of California" and its expansion threatens the survival of the agricultural industry and, finally, (c) the quality of the Colorado River water reaching Mexico is a serious subject of controversy between the U.S. and the Mexican government. Undoubtedly, the geothermal industry in the Imperial Valley will become involved in all of these problems.

#### 6.2.5 AN INTEGRATED APPROACH FOR THE GEOTHERMAL INDUSTRY IN THE IMPERIAL VALLEY

In theory, the process of geothermal power production is very simple. Figure 1 illustrates the typical basic system as visualized by many managements. However, as indicated before, the geothermal industry cannot be isolated from its environment and must find its place as an integral and viable part of our overall society. In addition, the "micro-society" in the Imperial Valley requires and demands special considerations. The elements of a properly functioning geothermal industry within its "micro-society" are complex and rather difficult to describe.

Therefore, the system described in Figure 1 must be considered an oversimplification.

Basically, the industry (a) must be profitable, (b) must solve all its technical and financial problems, and (c) should not raise any red flags when it comes to environmental or political problems.

These requirements may sound very difficult to fulfill. However, the grand scheme or, better, the scenario described below may provide the industry with an opportunity to take a large step in the proper direction.

### 6.2.6 DESCRIPTION OF A SCENARIO FOR AN INTEGRATED GEOTHERMAL INDUSTRY

The statement of work under this present contract contains tasks which may be difficult to understand considering only the technical aspects of a pure reinjection process. Economic, environmental and political considerations may force the U.S. geothermal industry to adopt processes which require new overall concepts for energy or power generation from our geothermal resources. This, in turn, may require a thorough reevaluation of the presently planned injection processes. The new injection processes to be developed cannot be understood unless they are viewed as an important and integral part of the entire geothermal power production.

Figure 2 shows a schematic diagram of a more advanced geothermal system. Three sources of liquid are indicated and utilized in this advanced geothermal operation:

1. The geothermal reservoirs.
2. The Salton Sea.
3. Colorado River.

Assuming that this scheme (see Figure 2) will work, only water vapor will be discharged into the environment. A small portion of this water vapor would be discharged through the stack of the cooling towers and would be optically evident. The vast majority of the water vapor losses would come through the use of condensate water which could be used for irrigation by the agricultural industry. These water losses would not be visible. This portion of the water losses is not due to the presence of a geothermal industry, but is naturally present in any agricultural irrigation system.

In this scheme, no gases from the geothermal reservoir are discharged into the environment. The gases (noncondensables) contained in the produced geothermal fluid will be vented before the fluid is fed into the first flash chamber. The vent gases containing some steam go through a heat exchanger or can drive a small turbine and are then sent to a smaller condenser. The noncondensables from this smaller condenser are sucked into the main vacuum system and combined with the noncondensables coming from the steam turbines. The combined noncondensables from the "vent condenser" and the "steam condenser" are recombined with the heat-depleted brine in the liquid lines downstream of the steam flash chambers. The liquid downstream of the brine-gas recombiner is then conditioned in brine conditioner No. 2 for reinjection into the reservoir. The condensates from the vent gas condenser and the steam condenser are combined and sold for agricultural irrigation.

Choosing the "proper" flash conditions in the brine system downstream of the gas vent or pre-flash tanks will allow mineral recovery through fractionated precipitation. In the first mineral recovery state (high temperatures: in excess of approximately 300 F), the heavy metals such as lead, silver, zinc, copper, etc., will be recovered. The siliceous materials will be recovered downstream of the brine conditioners No.1 and No.2. Brine conditioner No.1 is a solid remover and would be operated at low temperature and pressure (approximately 212°F and ambient pressure). This could be a reactor-clarifier supplemented by a properly designed chemically enhanced flocculation system. This system can be aided by chemicals to minimize the size and investment cost for this equipment. Brine conditioner No.2 would be a much smaller unit operated at low temperatures and pressures (approximately 250°F). Both conditioners could produce siliceous solids. The solids from conditioner No.1 would probably have a bulk density drastically different from those obtained in conditioner No.2. Both materials could be fairly clean and could find different applications such as an insulating material or as raw materials for the chemical, mining or any other industry.

The conditioned brine, recombined with the noncondensables from the gas condenser and the steam condenser would be reinjected into the reservoir. This would not only solve many environmental problems but would also adjust the pH of the reinjected brine, thus making the reinjected brine more compatable with the reservoir brine.

To overcome the fluid deficiency in the geothermal reservoir developed during production and reinjection, make-up fluids must be injected into the reservoir for two reasons:

1. Insufficient volumes reinjected into the reservoir can cause subsidence.

2. They can also cause serious pressure declines in the reservoir, thus leaving otherwise recoverable heat reserves behind.

The reinjection scheme shown in Figure 2 also boils down to a "heat-mining" process in the reservoir. The potential short comings of this process are obvious:

1. Chemical brine incompatabilities between the native reservoir brine, reinjected brine and injected foreign water can cause additional and/or new scale problems.

2. A premature break-through of the relatively cool reinjected brine and the injected foreign water could cause a disaster as far as longevity of the reservoir is concerned.

Both potential dangers are real and require special considerations. In previous reports, [1,2,24] we treated the break-through problem in some detail. We are confident that these problems can be handled properly or, at least, can be avoided through constant monitoring of the produced fluids through tracers [105]. Thermodynamic calculations and reservoir monitoring through tracers will allow a forecast of the potential problems and will permit the operator to readjust his operations before any technical, financial or environmental disaster occurs.

Admittedly, the required sophistication of the field operations may be a hurdle for some operators. On the other hand, the potential benefits of this complex process could give the field operators a strong incentive and a desired boost for the industry.

### 6.2.7 HOW FEASIBLE IS THE SCENARIO?

The geothermal industry may be somewhat wary of new concepts unless there is at least some evidence for their feasibility. This attitude is understandable in view of the technical problems presently encountered and, in some instances, still unsolved even in technically very simple geothermal systems. The more complex a proposed new system becomes the more problems are added and the more weary becomes the operator.

The system described above may offer technical difficulties because of its complexity and, more important, because of a number of critical uncertainties. Some of these uncertainties can be described as follows:

1. The Salton Sea water contains large concentrations of sulfate ions. The reservoir brines contain large concentrations of barium, strontium and calcium. How seriously will be the formation of $BaSO_4$, $SrSO_4$ and $CaSO_4$?

2. The Salton Sea water contains large amounts of suspended particles. How difficult and costly is it to remove these particles? What will be the damage if the

particles are not properly removed? What is the largest particle size which will not cause an injection well impairment?

3. How complex is the gas venting process and how can correct venting be handled efficiently in the field?

4. What are the power losses caused by the required recombination of vented gas and reinjected brine?

5. How can one make a mineral recovery process to a profitable enterprise?

6. How to make the recovered siliceous materials a saleable product despite their "toxic" contaminants?

7. What are the principles of the various brine conditioners required to yield an injectible brine? How costly and difficult are these conditioners to build and to operate?

8. How suitable is the condensate for irrigation or any other profitable use?

These questions could go on and on. However, the very basic question is not how to solve these problems, but is it worth attacking these problems at this very early stage in the life of the geothermal industry? Should one wait and/or slowly find solutions to the various technical problems and then incorporate the solutions into any of the developing geothermal plant operations?

We believe that a slow approach to solve these problems is not appropriate for a number of reasons:

1. Simple geothermal systems (as properly conceived by the industry) will solve short-term problems, but offer no long-term solutions to environmental and reservoir longevity problems.

2. Simple systems are more prone to develop technical and economical problems than the described more complex system because there is no provision to solve the already indicated problems. The simple systems may end up in a dead end street.

3. Changing a simple system into the described more complex system may not be economically feasible. To change an obsolete simple system into a better but more complex system may require nearly the same capital investment as starting the better but complex system from scratch.

Because of these reasons, we feel that the various processes described in Figure 2 deserve our full attention at the earliest possible time. Recent work by VR on water compatibilities and solid flocculation processes in oil fields have indicated that the scenario described in this report has an excellent chance to be adapted for the higher temperatures and different chemistry in geothermal operations.

### 6.3 INJECTION AND REINJECTION PROBLEMS MUST BE SOLVED

As outlined so far, there are many reasons for the reinjection of heat-depleted brines and the injection of imported brines. Table 1 summarizes the principal reasons for reinjection and injection. The rationale for the reinjection of heat-depleted brines (also the injection of imported brines) and the need for a detailed reinjection study have been dealt with in various publications [1, 40 through 42].

In recent years, various investigators from various parts of the world have described reinjection studies and associated problems [2,28,29,43 through 48].

The injection of large quantities of relatively cool brines into hot geothermal reservoirs is associated with many problems. These problems can be categorized into:

1. Reservoir problems.

2. Injectivity impairment problems.

The reservoir problems arise because of the premature cooling of the reservoir by the invading cool brines. There are various sources of information dealing with this aspect of reinjection [19,47 through 49]. These reservoir problems are not included in the present report. The premature breakthrough of the injected fluids and a possible means of retarding the breakthrough time by selective scaling are discussed in a separate report [19] under this study.

The second problem area directly related to injection and reinjection operations is the injectivity impairment. Injection of brines into geothermal reservoirs and the resulting injectivity deterioration of injection wells is of major concern for any geothermal operation. The open literature contains a number of publications related to injection problems and some possible remedies related to geothermal operations [32,37,50 through 58]. All these publications are site-specific to some geothermal operations. Unfortunately, none of them can be considered sufficiently comprehensive to be directly utilized as guidelines for the initiation of a new injection operation with different and/or varying site-specific conditions.

## 7.0 PROBLEMS ASSOCIATED WITH INJECTION OPERATIONS

There are many sources, starting from the inital drilling of injection wells through the production and subsequent injection operations that directly affect the injection of fluids in geothermal operations. Table 2 lists these sources. All of these sources effect the injectivity of an injection well and other field operations during the exploitation of a geothermal resource.

Drilling and completion operations can create skin damages in the injection wells or reservoirs and thereby reduce the initial injectivity of the wells. The reinjection of heat-depleted brines, the injection of imported brines and the injection of other fluids (gases and/or liquids) can all result not only in an injectivity deterioration of the injection wells but can also create problems at various other locations within the entire geothermal system. Thus, an understanding of the nature of the problems created by these various sources is important. Such an understanding will aid the following:

1. The design of any injection operation.
2. The early and critical analysis of injectivity losses of an injection well.
3. The stimulation design of an injection well.
4. The performance prediction of the entire geothermal system.

### 7.1 INITIAL INJECTIVITY OF INJECTION WELLS

The initial injection rate of a well depends upon many factors that characterize the reservoir and the well. These factors include the following:

1. Effective permeability of the reservoir at various critical locations (Keff).
2. Viscosity and density of injected fluids at the temperature and pressure of the reservoir ($\mu$).
3. Effective well radius (re).
4. Pressure radius (rw).
5. Reservoir pressure (Pe).
6. Applied injection pressure (Pw).

In addition to the above factors, other variables such as (1) the relative permeability of the displacing and displaced brines, (2) the viscosities of the two brines and (3) any "chemical effects" etc., may be important. However, for the discussion of injection operations, simplified injection rate formulations can be considered.

The fundamental equation [59] for the injection rate (i) of water forced into a well may be written as

$$i = \frac{7.082 \text{ Keff } h \text{ (Pw-Pe)}}{\mu \ \ln(re/rw)} \qquad \text{--- (1)}$$

The injectivity (I) may be defined as the rate of change of injection rate with the change in applied pressure.

That is:

$$I = \frac{di}{dPw} = \frac{7.082 \text{ Keff } h}{\mu \ \ln(re/rw)} \qquad \text{--- (2)}$$

This equation is a simplified form of the initial injectivity of a well.

From equation (2), it is evident that the effective permeability of the formation is one of the most important variable factors of an injection well. The other factors are relatively constant for a given situation. Thus, the initial injectivity of a newly drilled well has the maximum possible injectivity if no damage is introduced to reduce the permeability of the formation during drilling and completion operations. To avoid any such damages which may decrease the initial permeability of the reservoir rock or fracture conductivity, the operator pursuing an injection operation should be aware of the potential damages prior to the drilling of the injection wells. Two recent reports prepared under the present DOE/DGE contract discussed at length the various sources of damage expected during drilling and completion operations [19,22]. The nature of some of these problems are briefly reviewed here.

### 7.1.1 PERMEABILITY IMPAIRMENT DURING DRILLING OPERATIONS

In general, the damages to injection wells have their origin in the various physical and chemical interactions between the components of the drilling muds and the components of the geothermal formations. Table 3 gives a list of the various types of damages possible during drilling and completion operations. Glenn and Slusser [60,61] and Nicholson [62] have also summarized some of the various factors contributing to the damage to geothermal wells during and/or after the well drilling and completion operations.

Basically, two types of damages can be expected during geothermal drilling operations:

1. Physical Damage: the damage caused by the invasion of suspended particles of the drilling fluid into the porous formation.

2. Chemical Damage: the damage caused by the chemical reactions involving the invaded particles, drilling mud filtrate, chemical additives and the formation components.

It should be noted, however, that it is often very difficult to distinguish between purely chemical and physical causes for a wellbore and/or reservoir damage created during and after drilling operations. Considering the species of geothermal formations, the major factors contributing to drilling damages are as follows:

1. The reservoir rock is porous and, normally, is highly permeable and/or contains pronounced fractures, thus allowing drilling fluids to enter the reservoir.

2. The reservoir is under relatively low pressure and the drilling fluids are often applied at external pressures higher than the reservoir pressure during drilling, thus forcing the drilling fluids into the reservoir [63].

3. The drilling fluids entering the reservoir contain suspended particles. Both the entering suspended solids and liquids will generate a host of undesired reactions either through their own thermodynamic instability under downhole conditions or through chemical interactions between the various components of the invading drilling fluids and the materials that are native to the reservoir:

   a) The drilling and/or completion fluids entering the reservoir may be thermodynamically unstable under these high temperatures and may form chemical reaction products leading to subsequent reservoir damage.

   b) The temperature of the geothermal formations are high (in excess of $260^{\circ}$ F and sometimes as high as $800^{\circ}$F), thereby creating a favorable environment for many undesired chemical reactions between the various materials contained in the drilling and completion fluids.

   c) The formation fluids often contain fairly high concentrations of dissolved species which are chemically incompatable with the entering drilling fluids thereby also creating the basis for many undesired high temperature chemical reactions. These reactions include (but are not limited to) the precipitation of many scale forming and plugging solids.

Some of the components normally contained in drilling fluids may lead to formation damage through physical and chemical interactions. The major factors that contribute to this chemically induced formation damage are as follows:

1. The drilling fluids may contain various dissolved species (especially, the SO4-- and CO3-- ions), and can have an artificially high pH value thereby creating an environment in the porous formation which is favorable for sulfate, carbonate and hydroxide scale formation.

2. The drilling fluids may contain newly generated and very fine suspended particles (reaction products) which can invade and plug the pores or fractures in the reservoir rock.

3. The drilling fluids contain clay minerals (e.g., montmorillonite, attapulgite or sepiolite) which can enter the high temperature environment of the formation and can chemically or physically react to create a massive damage to the reservoir.

4. The drilling fluids may contain thermodynamically unstable additives or chemicals which can chemically react with each other or with the reservoir materials, thus causing various types of wellbore and reservoir damage.

Summarizing we can state that the drilling fluids may contain constituents which chemically react (a) by themselves, (b) with other components and/or (c) with any material native to the reservoir, thus causing a host of different types of chemically induced damage. This means, the major sources for a chemical wellbore and reservoir damage during drilling and completion operations must be seen in the chemical reactivity of various components of the geothermal formation and the drilling fluid system. Ennis et al [64,65] reported some interactions between recent studies on some drilling fluid and reservoir materials at simulated geothermal conditions and indentified some of these problems.

#### 7.1.1.1 PHYSICAL DAMAGE

Fine particles of clay solids are added (a) to increase the viscosity of the drilling fluid, (b) to improve the hole stability and (c) to aid in suspending the drilling cuttings in the drilling fluids [67 through 70]. These clay particles can form filter cakes within the wellbore or on the faces of a fracture. At high differential pressures, some of these clay particles can also enter the porous formation [63].

Comprehensive research work was conducted at Vetter Research as part of the present DOE/DGE contract to study the characteristics of the flow of particle suspensions through porous media [63]. The major problems of suspended particles in causing the permeability impairment of the porous formation are further discussed in Section 7.2. It is sufficient to state here that the presence of suspended particles in drilling fluid formations can result in a severe reduction of the initial injectivity due to physical damages caused during these drilling operations (see item 1 of Table 3). This usually results in the formation of a skin-damage which causes the initial permeabiltiy (or injectivity) of the native reservoir to be less than what is expected from the formation itself.

#### 7.1.1.2 CHEMICAL DAMAGE

This type of damage to the geothermal reservoir has its origin in the chemical reactions occurring during the drilling operations. The various types of chemically induced damages within the wellbore or reservoir have their origin in various sources as follows (see also Table 3):

1. The changes in the properties of invaded mud particles and other mud components in the drilling fluid within the environment of the geothermal formation due to the thermodynamic instability of the drilling fluid components.

2. The precipitation of salts or other solids due to the chemical reactions between the mud filtrate and the reservoir brine.

3. The disaggregation of clay minerals that are native to the formation caused by certain ionic species contained in the mud filtrate.

4. The conventional operating methods aimed at overcoming corrosion of drilling equipment at high temperature in the presence of highly saline geothermal brines.

##### 7.1.1.2.1 CHANGES IN PROPERTIES OF SOME INVADED MUD SOLIDS

The mud solids are normally difficult to define. When the drilling mud is freshly prepared and stored in mud tanks, the solid composition, concentration and particle size parameters are fairly well defined and could be measured. Subsequent to the starting of the drilling operation, all these parameters constantly change.

As mentioned in Section 7.1.1.1 (see also Section 7.2), the invaded mud solids (particulate matter) can directly affect the initial permeability of the formation. Such permeability impairment is a result of the fact that (a) some solids may form a mud cake on the sandface (within the wellbore or within a fracture) and (b) other solids may be small enough to invade the pores of the reservoir. Thus the permeability due to mud solids arises by physical blocking of pores or fractures (see section 7.1.1.1.1). In addition, the high temperature and highly saline nature of the formation brine can cause additional permeability impairment due to the chemical changes imposed on the invaded mud solids.

Drilling muds that are utilized in geothermal well drilling are normally formulated from an aqueous liquid phase with various solids added to provide weight, viscosity, particle carrying capacity and fluid loss control. Some of the solid additives include montmorillonite, sepiolite and attapulgite clays. In oilfield drilling, montmorillonite type clay has been in use for some time. The high temperature geothermal environment not only would create a gelation tendency to this type of clay [71], but also can form low grade cement (calcium montmorillonite) inside the pores of the formation near the wellbore. Field experiences in the Imperial Valley clearly demonstrated the severity of the damage caused by chemical changes of the invaded clays [62]. This problem is now widely recognized. Therefore, montmorillonite type clays are not generally used in the United States for high-temperature geothermal applications. Instead, sepiolite and attapulgite clays are used in drilling of geothermal wells. Very little information on the chemical damaging effects due to sepiolite and attapulgite clay particles seems to be available. On the other hand, recent literature contains information on the hydrothermal transformation of sepiolite and attapulgite to smectite type clays i.e., the normally non-swelling clays (e.g., sepiolite) become now swellable clays (e.g., smectites, stevensite). Such transformation is favorable for drilling operations because of the resulting alterations of the rheological properties of the drilling fluids [68]. However, there is considerable disagreement among the various studies on the hydrothermal transformation of sepiolite [84,85]. Of notable importance is the existence of a another species of clay, namely, the stevensite, and its relation to the clays used in drilling fluids [86 through 88]. Guven and Carney [88] reported the effect of pressure, temperature and the presence of various alkaline metals on the hydrothermal transformation of sepiolite to stevensite. Carney et al [85] utilized the information of these transformation studies in formulating some fluid loss control agents for geothermal drilling applications. However, the impact of such transformation reactions on the damage to the formation is not known and needs further study.

#### 7.1.1.2.2 DEGRADATION OF CHEMICALS USED DURING DRILLING OPERATIONS UNDER GEOTHERMAL DOWNHOLE CONDITIONS

Many chemicals are added to drilling muds for various reasons. These chemicals include the fluid loss agents, scale inhibitors, weight increasers, corrosion inhibitors, friction reducers, and clay stabilizers. During drilling operations, all these additives can enter the reservoir and subsequently be exposed to the high temperature of the geothermal formation. This generates numerous possibilities for various unwanted high temperature reactions and subsequent chemical alterations of these additives. There is a notable scarcity of information about the degradation or other chemical changes induced on these additives under downhole conditions. Very few studies are reported in the literature [73 through 76]. These few studies clearly demonstrate that the degradation products can cause severe damage to the porous reservoir rock.

Numerous other soluble mud additives are highly suspect to create similar chemically induced problems. The only sure way of determining the extent of damage by a given chemical additive is through testing it under simulated (or real) field conditions.

#### 7.1.1.2.3 THERMODYNAMIC INSTABILITY OF MUD FILTRATE

During the initial stages of drilling into a geothermal formation, the solid particles as well as the liquid components of the drilling fluid enter the pores of the reservoir. The depth and the rate at which the filtrate enters the porous matrix of the reservoir are determined by many factors. Some of these factors include, (1) the local (microscopic) permeabilities of the reservoir, (2) the viscosity of the fluid at the temperature and pressure near the invaded region, (3) the pressure difference between the wellbore and the near wellbore region of the reservoir (differential pressure).

The filtrate that entered the formation can cause permeability losses through the precipitation of salts which occurs due to the thermodynamic instability of the entering fluids and the reactions between mud filtrate and reservoir brine. Thus, damaging precipitations are caused by two different types of thermodynamic instabilities:

1. The thermodynamic instability of the dissolved species in the filtrate mainly due to temperature changes.

2. The thermodynamic instabillity of the dissolved species through mixing of incompatible liquids.

The principles behind these precipitations and the permeability impairment induced on the formation are the same as those described in section 7.2.

Besides the prediction of scale formation, two other factors are extremely important in determining the near wellbore damage due to the mixing of the drilling mud filtrate and the reservoir fluids. These two factors are, (1) the determination of the amount of filtrate that invaded the formation water, and (2) the mixing proportions of the two waters. Millar and Buckles [90] have used radioactive techniques using tritiated water to determine the drilling mud filtrate which has invaded the formation water. Using this technique, the radial extent of the invasion was determined. In a similar way, the invasion of the core samples can be determined by comparing the pore water with the drilling fluid [77,78].

A calculation of the mixing proportions of the drilling mud filtrate and the formation water at various locations is needed to determine the amount of scale formed during and after a drilling operation. This is generally done through models based on the dispersion equation. Some of the concepts that are pertinent to the drilling mud filtrate and the formation can be found in the literature on the mixing of fluids in porous media [77 through 83]. However, to our knowledge, none of these techniques have been used for actual investigations of drilling damages in the field.

7.1.1.2.4 DISAGGREGATION OF CLAY MINERALS

Certain clay minerals that are native to the reservoir may be extremely sensitive to the various ionic species (including pH) of the drilling mud filtrate. These clay minerals may disaggregate upon coming in contact with these ionic species. This, in turn, can alter the initial permeabillity of the reservoir rock. Specific information related to this type of chemical damage that is applicable to geothermal drilling operations is not available in the open literature. However, based on the information from various literature sources [91 through 94], the effect of the following clays on the damage during drilling operations should be considered:

1. Montmorillonite,
2. Chlorites,
3. Smectities,
4. Illite,
5. Kaolinite.

It should be mentioned here that chlorites (non- expandable) are the more common clays for most of the high temperature geothermal reservoirs. The non-expandable clays such as chlorites and illites can absorb enough water in their characteristic platelet-type structure and consequently, thus making the platelets easily slip and cleave the original clay particles into smaller particles. Illite and chlorite, normally bonded by K+ ions, can degrade and lose the ions by leaching when exposed to slightly acidic fresh water. After removal of potassium ions, illite will expand to 24A (normally 9.5A) [65]. This, by itself, is a rather large expansion and can generate problems. Even if the individual particles of these clays do not disintegrate, all clays are subject to deflocculation, a condition wherein agglomerated masses of clays (floc) are broken up and dispersed, thus leading to moveable fines within the reservoir. The presence of salt water in the rock pores causes the clays to exist in a flocculated condition. Neesham [89] has demonstrated the physical appearance of some of these clay flocs by using SEM microphotography. He found that kaolinite exists in discrete, plate-like particles scattered throughout the pore system. Illite, chlorite and montmorillonite, on the other hand, are attached to pore walls to form a relatively continuous and thin (less than 12 microns) coating or "pore-lining". This coating can extend far into or completely across a pore or pore throat to create a bridging effect. This microporous structure is comparatively easily broken down. When fresh water (such as drilling mud filtrate) enters the rock, the clays will be in a deflocculated condition. The individual particles will then be entrained by the fluid, transported, and deposited as microscopic filter cakes plugging narrow pore openings. Such internal filter cakes can considerably reduce the permeability of the reservoir rock [89].

One of the most damaging clay substances is montmorillonite. This type of clay is found to be present in high temperature geothermal reservoirs only in greatly reduced amounts, or to be completely altered due to the high temperatures found in the geothermal formation. However, it should be pointed out that if montmorillonite is present even in small amounts, this could become significant from the point of view of drilling damage because of the proximity of the expected damae to the wellbore of productive portions of fracture faces. It is sufficient to state here that a knowledge of the nature of clay minerals in a given formation and their chemical alterability may become important to any drilling operation.

#### 7.1.2 INITIAL PERMEABILITY IMPAIRMENT DURING COMPLETION AND/OR WORK-OVER OPERATIONS

The initial reservoir characteristics can also be detrimentally and drastically impaired during normal well completion operations. This initial damage related to completing a geothermal well after the drilling operations is related to the fluids utilized during the completion of a well. Three different types of fluids are of interest:

1. Cement slurry to set casing or any other downhole hardware.

2. Fluids used to control the well.

3. Fluids utilized to clean the well during and after completion.

Some of the problems related to these fluids are described below:

7.1.2.1 CEMENT SLURRIES AND CEMENT DEBRIS

Some of the cement slurries used to complete a well or the solid cement debris after using the slurries may enter the reservoir or may be retained on the open sand face. The effect resulting from the cement debris reaching these critical locations are similar. A well injectivity problem will be created farther away from the wellbore or near the sandface (skin effect). These damages in some distance from the wellbore are difficult to remove in a geothermal well (see section 7.2.1.2.2).

7.1.2.2 WELL CONTROL FLUIDS

Quite often, the wells must be controlled by injecting fluids into a well. These fluids are normally cold but will heat up during waiting periods. The heated fluid should still have a density large enough to insure proper well control. To achieve this proper fluid density various types of salts are dissolved in the injected cold fluid. None of these salts should cause any undesired physical or chemical interference upon any reaction under downhole conditions. Frequently, the wrong salts are used for these well control fluids (mainly kill fluids). Subsequent chemical reactions (scale formation) occur upon mixing of these fluids with the native reservoir fluids.

7.1.2.3 WELL CLEANING FLUIDS

To clean an injection well after drilling, completion and/or any work-over job, it is adviseable to back-flow this well for numerous reasons prior to starting the injection operations (see section 8.0). However, quite often a simple back-flowing will not yield the required cleaning effect and cleaning fluids may have to be applied to bring the well into proper conditions.

Various types of cleaning fluids are used for these cleaning operations:

1. Neutral fluids such as available waters.

2. High pH fluids, i.e., waters having a high pH value due

to the addition of caustic type materials.

3. Low pH fluids, i.e., acid-type mateials.

De facto, this fluid could be considered a stimulation fluid. The problems generated or commonly encountered by this type of stimulation are described in section 7.2.6.2 of this report.

## 7.2 INJECTABILITY AND INJECTIVITY PROBLEMS SUBSEQUENT TO INITIAL INJECTION OPERATIONS

In section 7.1, the damage to injection wells during drilling operations and its effect in decreasing the initial injectivity are discussed at length. Even if all these damages are eliminated and the initial injectivity is restored to the injectivity of the "damage-free" reservoir, the problems related to long-term injection operations are not over. As the injected fluid enters the formation, other factors are introduced which effect the behavior of the injection well. These factors are influenced by the following items:

1. The physical reservoir aspects such as the increase in flow resistance as the injected fluids enter the reservoir and spread toward the producing wells.

2. The quality of the injected brine or the injectability of the injection brine which directly affect the effective permeability of the injection well.

3. The degradation and/or other chemically-related reactions of the various chemical constituents of the reinjected or injected fluids.

All the above items can affect the injectivity of the injection well. The first item of the above list is not discussed in this report. However, it might be stated here that it is important to be able to distinguish between the injectivity decline due to natural reservoir fill-up and the injectivity decline caused by physical and/or chemical reactions of the injected fluids or between injected fluids and the reservoir materials, e.g., plugging of the porous reservoir rock by particulate matter. Various well-testing methods are available to distinguish between these two major sources of injectivity decline [101 through 104] (see also section 7.2.5).

The next several sections discuss the various criteria for the injectability of the injected fluids and the effects of the injected fluids on the injectivity of the injection wells.

### 7.2.1 INJECTABILITY OF BRINES

The operator of a geothermal field must know the injectability requirements for the reinjected and injected fluids under his very site-specific conditions. Even to define a "proper injectability" is quite often a serious problem. Frequently, short-term injection tests with a certain brine and a certain injection well are run [13] (see also section 7.2.5). If no obvious injection problems are encountered, the brine is considered "injectable". This, of course, is an archaic and unacceptable way to define or to determine injectability.

As shown in Table 4, the true fluid injectability is determined by a large number of critical variables. As shown later in this report, even an absolutely clear brine (i.e., a brine containing no suspended particles at all) may not have the required injectability because of chemical interactions between the injected brine, the reservoir rock and/or the reservoir fluids under reservoir conditions. On the other hand, an injected brine can have a satisfactory injectability despite the fact that it contains extremely large concentrations of suspended particles if these particles stay suspended and will flow through the reservoir rock without impeding the overall brine flow.

It becomes obvious that it is rather difficult to define and to determine brine injectability. Not a single variable (as shown in Table 4) but all the variables in their entirety will determine the degree of brine injectability. Unfortunately, the authors of this report do not believe that it is presently possible to assign a number or a "degree" to the injectability of any injected or reinjected brine under actual field conditions.

A perfect injectability is encountered if all of the following conditins are met:

1. The injected fluids do not chemically react with reservoir materials by forming any materials that will lead to a deterioration of the injectivity.

2. The injected fluids do not contain any materials (e.g., suspended particles) that will lead to another chemically-induced type of injectivity deterioration.

3. The injected fluids behave physically in such a way that no injectivity deterioration is encountered, for example, through alteration of the contact angle (wettability) by adsorption of the additives.

In essence, a perfect injectability is encountered when the native injectivity of an undamaged injection well and reservoir remains unchanged during the entire duration of a geothermal reinjection or injection operation.

If any of these conditions are not met, an "imperfect" injectability must be assumed. A proper field management will require a thorough knowledge of the injectivity deviation from the point of being perfect. This is not a philosophical matter.

If any deterioration of the "perfect" injectability is encountered the resulting injectivity declines will cause costly repairs (e.g., stimulation jobs, see section 7.2.6) or even more costly well replacements. Furthermore, the danger of causing intermittent or slow injectability changes must be monitored. Counteracting measures must be taken before the injectivity declines become evident. In other words, a "quality control" of the reinjected and/or injected fluids must be devised. This becomes extremely difficult if the quality parameters (i.e., variable determining the injectability, see Table 4) can not be quantified in an acceptable way.

The various problems causing this lack of an injectability quantification are described in the following sections of this report.

#### 7.2.1.1 CHEMICAL COMPOSITION OF REINJECTED AND INJECTED FLUIDS

To explain the problems related to the injectability of fluids in a geothermal operation, the chemical behavior of all injected and native fluids play a key role. The chemical behavior of the various fluids involved in geothermal reinjection and injection operations will govern the injectability of any fluid in a number of different ways:

1. The heat-depleted brine to be reinjected is normally thermodynamically very unstable and can form precipitations under field conditions. These precipitation reactions at any time and location are dictated not only by the chemical composition of the heat-depleted brine and the physical conditions (temperature, pressure) but also by the effects of mixing these brines with other materials already present in the injection reservoir. This means that there are basically two types of precipitations:

   a) Naturally occuring precipitations due to the cooling and flashing of the produced and thermodynamically unstable geothermal fluids.

   b) Precipitations caused by the chemical incompatability of the heat-depleted brine and the native reservoir materials.

2. The gases separated from the produced fluids can have a serious effect upon the chemical composition of any reinjected (heat-depleted) brine and/or any injected (foreign or imported) fluid. Thus, further complications will arise as far as injectability of the reinjected or injected fluids is concerned.

3. Any foreign or imported liquid to be injected may become either thermodynamically unstable or may lead to chemical reactions with the reinjected fluids and/or the native reservoir materials. Thus, still further complications must be expected as far as the injectivity problems are concerned.

The problems arising from the chemical composition of all fluids of concern and their relationship to injectability and injectivity are described in some detail below:

7.2.1.1.1 RESERVOIR FLUIDS

The reservoir fluids being produced are utilized by extraction of energy from these fluids. This process is accompanied by a serious heat-depletion during production and utilization. Depending upon the chosen and/or given details of the production and utilization processes, the resulting heat-depleted fluid will have varying chemical composition [12,37]. This composition is not only affected by thermodynamics but also by the kinetics and hydrodynamics. For example the compositions of the fluid and suspended particles of a heat-depleted geothermal fluid may change drastically with the production and utilization process even though the produced fluids conditions (production reservoir conditions) and the end conditions remain the same (or different) [12,37].

These changes in the fluid composition from production reservoir conditions to reinjection conditions are caused by:

1. Temperature and pressure declines associated with various types of flashing.

2. The kinetic and hydrodynamic reactions that occur during the various changes in the above thermodynamic conditions.

No matter what production, utilization and reinjection processes are used, the critical start of the chain reactions is always given by the thermodynamic variables of the reservoir fluids under static (i.e., non-producing) conditions. One of these critical thermodynamic variables is the chemical composition of the reservoir fluids.

All reinjection operations must take into account this critical reservoir fluid composition and the changes of the fluid composition as these fluids are produced, utilized and reinjected. Naturally, the brine to be reinjected has undergone drastic changes of its composition. These changes can be accompanied by precipitations of various types which will also affect the injectability of the heat-depleted brine [1,12,37].

### 7.2.1.1.2 HEAT-DEPLETED GEOTHERMAL BRINE

At this point, we would like to emphasize the injectivity problems caused only by the compositional change of the liquid phases during production and utilization operations. Table 5 lists the types of damages expected during reinjection of heat-depleted brines.

The heat-depleted brine is chemically quite different from the geothermal brine under static reservoir conditions:

1. Due to flashing of reactive gases [18,26,107] the critical pH value of the two liquids can be quite different. For example, an East Mesa reservoir brine may have a pH of approximately 5.0 whereas the reinjected brine may have a pH as high as 9.2.

2. Due to the flashing of water vapor (steam), all non-flashing constituents of the reservoir brine are concentrated in the reinjected brine. For example, the San Vito reservoir fluid (Italy) may undergo a 50% steam flash thus concentrating all non-flashing and non-reactive constituents in the reinjected brine by a factor of 2.0.

3. Due to the flashing of chemically reactive non-condensables (e.g., $CO_2$ and $H_2S$) the chemically reative constituents in the remaining liquid phases may be drastically reduced because of precipitations (e.g., $CaCO_3$ and $PbS$).

Considering all the resulting differences in the composition between native reservoir fluids and the heat-depleted brine to be reinjected one can note the potential for an entire set of chemically related injectabillity problems becomes obvious. The heat-depleted brine which is reinjected into the reservoir may become chemically incompatible with the native reservoir brine under reservoir conditions even though the heat-depleted brine itself originated from this reservoir.

### 7.2.1.1.3 IMPORTED OR FOREIGN BRINE INJECTION

Injection of heat-depleted brines will pose numerous technical problems for an operator of a geothermal field. Assuming that the technical problems related to the reinjection of the heat-depleted brines into a producing reservoir can be solved, the operator will still be confronted with some annoying problems related to the injection of liquids. It may become necessary for an operator to inject foreign waters (i.e., waters which are not native to his producing reservoir) for a number of reasons. Some of these reasons include the following:

1. Make-up water injection to prevent subsidence and to

comply with other legal or environmental regulations.

2. Foreign water injection for reservoir pressure maintenance and advanced heat-mining.

3. Waste water disposal, i.e., injection of aqueous wastes generated during various operations of the surface facilities in the field.

Injection of such foreign waters will result in numerous problems for the routine operation of a geothermal field. Table 6 summarizes the types of damages expected during the injection of imported or foreign waters. The operator will, most likely, have very little choice in the selection of foreign waters. He may be confronted with the situation that only one or two waters are available in his area. This means that the operator must thoroughly evaluate the available waters for their suitability as injection fluids. If the available waters are unsuitable for injection, none of the above mentioned operations may be possible, thus generating a severe handicap for the technically and econimcally feasible operation of a given geothermal field.

On the other hand, technically proper and economically feasible ways of pretreating these available but otherwise unsuitable waters may be possible. In order to determine the suitability of the available waters for injection, an evaluation of major injectability problems must be performed prior to start-up of the injection operations. The major problems can be divided as follows:

1. Physical and mechanical problems.

2. Chemical problems.

A short description of these problems is given below.

7.2.1.1.3.1 PHYSICAL AND MECHANICAL PROBLEMS

The waters available for injection may contain considerable amounts of suspended particles. These particles can invade the porous media and physically block the pores of the formation. This will make any further water injection difficult or impossible. This topic is dicussed further in Section 7.2.1.2. These particles must be removed by filtration, sedimentation or any other method. This alone will generate a considerable number of problems. For example, the New River water in the Imperial Valley contains as much as 400 milligrams of organic solids suspended in each liter of water. The horsepower and/or storage facilities required for a mechanical brine pretreatment (removal of suspended solids) and storing of the collected solids may become economically unaffordable. However, if the suspended particles contain commercially valuable materials, economics may allow for particle removal. For example, the suspended solids may become useful as a fertilizer or may have to be removed for environmental reasons anyway at the source of the "dirty" foreign water. In addition, the possible recovery of dissolved solids (see next section of this report) may justify the cost of suspended particle removal.

7.2.1.1.3.2 CHEMICAL PROBLEMS

The chemical problems related to the injection of large quantities of imported waters into a geothermal reservoir are generated due to the thermodynamic instability of the brine. This will result in supersaturated conditions with respect to certain scale forming compounds and in a subsequent formation of scale. The supersaturation is caused by:

1. An increase in temperature as the injected brine reaches the reservoir.

2. By mixing of the injected brine with the reservoir brine in various proportions.

The impact of these two different supersaturation causing tendencies on the precipitation at various locations in a geothermal operation were described previously [11,20 and 36].

7.2.1.1.3.2.1 PRECIPITATION UPON HEATING OF FOREIGN OR IMPORTED WATERS

If one considers the geothermal operations of the Imperial Valley, three souce waters are available for the purpose of injection. These three source waters are:

1. Salton Sea water

2. Colorado River water

3. Ditch water

Geothermal operations from other regions might have other surface source waters that can be used for injection purposes. Irrespective of the sources of available waters for injection purpose, the following factors are common to all the surface source waters:

1. They are generally saturated or undersaturated with respect to scale forming compounds at atmospheric conditions. In other words, these waters are thermodynamically stable at the ambient conditions.

2. They contain substantially high concentrations of dissolved $SO_4^{--}$ ions (for example, the Salton Sea water contains as much as 8100 mg/l of $SO_4^{--}$ ions).

3. They contain high concentrations of $HCO_3^-$ ions.

4. They contain a certain amount of dissolved $Ca^{++}$, $Ba^{++}$ and $Sr^{++}$ ions (the potential scale forming alkaline earth metal ions).

5. They contain varying amounts of other dissolved species ($Na^+$, $K^+$, $Cl^-$, etc.) which control to some extent the thermodynamics of the aqueous medium.

Even though the source waters are thermodynamically stable under ambient conditions, they are prone to become unstable when they are heated to the temperatures found under downhole or reservoir conditions. This problem arises because of the reverse solubilities of certain scale forming compounds ($CaSO_4$, $CaCO_3$ and $SrSO_4$). This can be illustrated with the example shown in Figure 3, which illustrates the precipitation problem that is expected upon heating Salton Sea brine. From the figure, it is evident that there is a large potential for $CaSO_4$ precipitation which can result in a danger of plugging the reservoir close to an injection well. This $CaSO_4$ precipitation will generate long term damage of the injection wells and the reservoir zones close to the injection wells unless preventive steps are taken. Some of the ways of preventing such injection well damages are discussed in Section 8.0.

#### 7.2.1.1.3.2.2 PRECIPITATION DUE TO MIXING OF INCOMPATIBLE WATERS

The mixing of foreign water with the reservoir brine can result in precipitation at various locations in a geothermal facility involving injection and production operations. This precipitation can result in a serious damage not only to the injection operation itself but also to the entire geothermal operation [11,20,36]. The precipitation process caused by incompatible water mixing is highly complex because of the interaction of a number of variables. These variables include the following:

1. Temperatures and pressures at all locations in the direction of flow of the injection water. This includes all the temperatures and pressures (a) in the injection wells, (b) throughout the reservoir, (c) in the production wells and (d) at the surface facilities.

2. The mixing ratios of the native reservoir water and the injected foreign water.

3. The complete compositions of the injection and the reservoir waters.

Any geothermal operator who is planning to start an injection operation should evaluate the problem of water incompatibilites using scale simulation models for his geothermal system. The importance of such an evaluation has been illustrated fully by examples in earlier publications [11,20]. Subsequent to this evaluation, the operator should perform some tracer studies to further understand the mixing pattern of the various waters in the geothermal reservoir system. Some of the solutions of overcoming the problems due to the mixing of incompatible waters in a geothermal operation are discussed in section 8.0.

#### 7.2.1.2 PROBLEMS RELATED TO PHYSICAL PROPERTIES OF SUSPENDED PARTICLES

One of the most important factors that must be considered in evaluating the injectability of the brines (whether heat-depleted brines or foreign brines) is the suspended particles. Any geothermal operator pursuing injection operations must be fully aware of the importance of these suspended particles. The suspended particles in the injection brines can result in a drastic and short-term decrease in permeability as the injection operation progresses. Different mechanisms have been proposed by different investigators to explain the particle flow through porous media and the damage to the formation by these particles. This subject is rather complex and as such no unified model explaining all the aspects of reservoir damage is presently available [19].

Eventhough the problem is far from being solved, there are some points of agreement among various investigators regarding the importance of various factors such as flow rate, particle size, particle shape, etc., on these various damage mechanisms caused by suspended particles. A recent report under the present contract summarizes the literature information as well as some laboratory experiments conducted at VR on the subject of particle suspensions through porous media [19].

The quickest solution to eliminate any problems related to suspended particles seems to make the injection brines "free" of any particles. This may become an impossible situation from the point of view of technical feasibility as well as of economics. The suspended particles are constantly being generated at various locations of the complete geothermal system. A geothermal operator must be aware not only of the actual damage (location and type of damage) caused by the suspended particles but must also be aware of the origin of the various suspended particles as well as various means of measuring and/or monitoring them. These topics have been previously discussed fully in other reports [10,12]. In the present section, the various aspects of the suspended particles are briefly reviewed.

##### 7.2.1.2.1 ORIGIN OF SUSPENDED PARTICLES

The suspended particles exist whether the injection water consists of heat-depleted geothermal brine or imported brine or a combination of various brines. However, the severity and the variety of suspended particles are much larger in the case of a heat-depleted brine. Table 7 gives the various possible sources of suspended solids in a heat-depleted brine. Any geothermal operator should be familiar with these sources of suspended particles and apply the knowledge to the situation encountered in his geothermal operation. A detailed description of these various sources of particles in geothermal operations can be found in a separate report [1].

At this point, we would like to emphasize that the suspended particles can have numerous sources of origin even within the same field. The particles suspended in a heat-depleted brine prior to reinjection have basically two types of origin (see Table 7):

1. Reservoir fines produced with the fluids.

2. Solids formed by various precipitations during drilling, production, and utilization of the geothermal fluids.

Depending upon the native materials in the reservoir, the varying conditions of drilling the wells, production methods and utilization processes, varying types and amounts of suspended solids will be found in the heat-depleted brine prior to reinjection even though the collected liquid (heat-depleted brine) has the same point of origin. This dependency of the type and amount of solids as a function of the numerous variables generates a rather complex set of problems for the operator of a geothermal field. Even small changes or variations of any of the sources of the suspended solids will greatly effect the solid type and amount to be removed prior to reinjection (see Sections 7.2.1.2.3 and 7.2.1.2.4).

#### 7.2.1.2.2 TYPE OF DAMAGE BY SUSPENDED PARTICLES

Irrespective of their sources of origin, the suspended particles in an injection water can cause reservoir and/or well damage which can result in a drastic reduction in the injectivity of an injector. There are several ways in which this reduction in injectivity can occur. The most obvious ones are listed in Table 8. It must be emphasized, however, that the exact mechanism of damage to the well and/or formation by suspended particles is not clear-cut and there are a host of interacting mechanisms that may contribute to a given overall damage. The various studies on particle flow through porous media (including the one done at VR under the present contract) are summarized in a recent report [19]. Some of the conclusions of these various studies are as follows:

1. The damage to the porous reservoir rock by suspended particles ( i.e., the location and extent of damage) is dependent upon many factors. They include the ones

listed below:

a) Size and size distribution of the particles.

b) Shape and shape distribution of the particles.

c) Concentrations of the particles.

d) Chemical and physical properties of particles.

e) Various characteristics of the formation.

f) Flow velocity of the suspension.

A brief description of the above parameters and the difficulties of measuring them can be found in separate reports [10,12].

2. Submicron particles can generate a damage within the porous medium. Particles having a critical minimum size can not generate damage collars within the reservoir around the wellbore whereas large particles will not cause any damage inside the reservoir.

3. The depth of particle penetration inside the core is related to the flow rate for a given size and concentration of particles. The higher the flow rate, the greater is the depth of penetration of the particles inside the core at a given particle size. Essentially submicron particle distributions with a median size of about 0.7 micron are completely retained by Berea sandstone cores (up to 200 md) and do not break through at rates varying from 1.0 to 10.0 ml/min. The situation is expected to be much more complex for the case of the flow of particle suspension through the porous formation of the reservoir rocks.

4. Particles having a size distribution with a median of approximately 0.5 micron are observed to pass through Berea sandstone cores (up to 200 md). Permeability damage for a given concentration of these particles appears to be inversely related to the flow rate. The lower the flow rate the higher seems to be the permeability damage.

5. For cores mounted in tandem, a filter cake was observed on the injection face of each core segment at various flow rates. This suggests that similar cakes would form at fractures inside the reservoir around injection wells. It also means that core flow test experiments using cores mounted in tandem are suspicious at best if the data are related to particle movements.

6. Submicron particles at a given concentration and size distribution can be completely filtered out by a 5.0 micron millipore filter while they break through two Berea sandstone cores (up to 200 md) mounted separately but in tandem. This means that filter data cannot be compared with or related to core data as commonly suggested in the literature or as done in routine field operations.

7. An optimum degree of particle filtration prior to injection of liquids should be determined by site-specific conditions. This optimum degree of filtration depends on:

   a) Injection rate after filtration.

   b) Characteristics of particles suspended in the liquid prior to and after filtration.

   c) Physical and chemical characteristics of the reservoir rock accepting the filtered brine.

8. Damage collars inside the formation can be generated by invasion of submicron particles. However, the precise mechanism of this damage collar formation is not clear and seems to be extremely complex.

In spite of a large body of evidence for the damage to the porous formation by particles, no generalization can be made, at the present time, on the exact mechanism of damage formation by a given particle suspension system within a given reservoir.

### 7.2.1.2.3 PARTICLE CHARACTERIZATION AND MONITORING

In any injection program pertaining to geothermal operations, strict quality control should be maintained through particle characterization and monitoring. The importance of particle monitoring and some of the problems associated with such particles have been discussed fully in various reports on the present contract and some related to publications [10,12,13]. Some suggested methods of monitoring particles suspended in fluids prior to injection are discussed in section 8.2.2.1.

The main problems related to particle characterizations and monitoring in a geothermal field operation are as follows:

1. It is not precisely known which is the maximum size of particles that can be left in the reinjected brine without causing any damage. Presently, it is assumed that this maximum particle size can be as small as 0.5

micron for some operations (e.g. Imperial Valley). Most particle monitoring equipment is "blind" for these small particles. For example, a Coulter Counter can "see particles" having a size of only 1.0 microns and larger. This means, there is an accute problem regarding instrument sensitivity.

2. The particles measured in a cooling or cooled down sample of a geothermal brine are quite different from the particles in the same brine under in-line conditions. This means, in-line monitoring as opposed to sample measurements must be performed to determine the critical particle characteristics under actual field conditions. Most known particle monitoring devices do not lend themselves to the high temperature and/or severe scaling conditions encountered in most geothermal systems.

3. Most particle monitoring devices give only a certain and limited amount of information regarding the critical particle characteristics. This means, more than one type of monitoring device may have to be used to obtain all the critical information required for an effective brine quality control in the field. Rather sophisticated instrument combinations may have to be used for this purpose. Each different type of geothermal operation may have to use a different type of instrument combination.

Summarizing we can say that the "State-of-the-Art" related to the required methods and hardware for a reliable particle monitoring in the field is far from being highly developed and sufficient for a properly designed and run field operation.

7.2.1.2.4 PARTICLE REMOVAL

Any injection, especially the reinjection of the heat-depleted brine in geothermal operations, should remove the suspended particles in brines. Some ways of handling these suspended particles are described in section 8.2.2.1.

The main problems encountered for an effective and optimum particle removal are generated as follows:

1. The amount (concentration) and type (size distribution, composition, shape, etc.) of all particles upstream of a reinjection well will depend upon various reservoir characteristics and production and utilization parameters as described in Section 7.2.1.2.3). Any particle removal process will depend upon these large multitude of characteristics and parameters which are not only unknown by the operator but may also drastically change during any variation of the field

operational practice.

2. It is normally unknown which particles will generate injectivity problems and which ones will not (see Section 7.2.1.2.2). Without knowing the damaging effect of the various types and amounts of the suspended particles it will become impossible to operate a correct particle removal process with all required design and operational features.

3. Without having a constant and reliable particle monitoring system installed and operational in a geothermal reinjection operation, the operator will be unable to maintain a high injectivity of his reinjection wells. This means, he will be unable to avoid any future damage of the wells.

To pursue different routes for an effective particle removal, trial and error methods are frequently applied in the field. These trial and error methods are technically and economically not viable for a number of reasons:

1. If an error is encountered during these experimental periods the well damage may become very extensive and either an expensive stimulation work-over or redrilling is required, thus adding large costs to the overall operations.

2. The trial and error method may tell the operator only what he should not do without giving him a viable solution to the encountered problems of particle removal.

3. Even if he uses certain types of particle removal equipment in trial and error procedures, he will financially not be able to constantly replace or retrofit his system until he comes up with a viable answer.

Despite these common and, frequently, well recognized shortcomings of these trial and error methods, they are still the standard practice in the geothermal industry. The decision to use these trial and error methods is normally made after ignoring some of the main technical problems associated with geothermal reinjection operations:

1. The concentration of damaging particles in a heat-depleted geothermal brine may be low. However, huge amounts of brine have to be reinjected per reinjection well, thus causing a relatively large damage in a relatively short period of time.

2. The heat-depleted brine must be reinjected at relatively

high temperatures (90-100°C), thus rendering the "heat-depleted" brine thermodynamically unstable. Some of the damaging particles may form downstream of the last particle removal and/or particle monitoring equipment. This means, the operator may not properly judge any of these processes until the actual damage has already occurred.

### 7.2.2 PROBLEMS RELATED TO REINJECTION OF GASES

The liquid-dominated geothermal brines are complex aqueous solutions which consist not only of the ionic species of dissolved solids, but also of the various components of the different gaseous species. The gaseous species of interest include CO2, H2S, N2, NH3, hydrocarbons and inert gases (Ar, He, etc.). These gases are dissolved in the aqueous media of the geothermal fluids and are under equilibrium conditions at the temperature and pressure of the reservoir. During the production of the geothermal fluids from the reservoir these gases are emitted due to pressure decreases accompanied by temperature decreases. The determination and handling of these gases is important for several aspects of a geothermal development.

The non-condensable gaseous discharge from a geothermal power plant operation is important for various reasons. These reasons include:

1. An excess amount of non-condensable gases (particularly CO2) would affect the efficiency of a turbine operation (and condensor) and, as a result, would have deterimental effects on the overall efficiency of the power plant.

2. The emission of non-condensable gases (particularly CO2 and H2S) would affect the pH of the effluent brine and generate a potential for severe scale formation in the producing wellbore and all the surface equipment installed in a given field.

3. The emission of non-condensable gases (particularly H2S) into the atmosphere could cause environmental problems or concern.

4. The non-condensable gases may become a highly valuable commodity.

5. The reinjection of the non-condensable gases may be beneficial to the entire geothermal operation.

The important considerations associated with these various aspects of the different non-condensable gases have been discussed previously [18,107]. These reports [18,107] also discuss the methodology of calculating the gaseous emission from geothermal operations.

From the above discussion, it is obvious that handling of gaseous emissions is a major task. Some qualitative means of handling the gaseous emissions through a rather complex scheme of an integrated geothermal operation was discussed previously in section 6.0 (see also Reference [2]). The exact procedure to be followed in handling non-condensable gases depends very much on the nature and quantity of the gases contained in a given reservoir fluid.

The handling of the non-condensable gases is accompanied by some minor problems:

1. Flashing of any gases from the liquid phase into the vapor phase depends upon the exact flash conditions (temperature, pressure and reservoir fluid composition). Handling of the gases will drastically vary with any of the pressures and temperatures of any of the flash and separation processes.

2. Changing of pressures and temperatures of any field operation may require costly retrofitting of field installations at any future time to accomodate the then different gas behavior.

3. The gas content of the reservoir fluid may change with the life time of the field operations [18,107] thus causing future problems regarding retrofitting of the existing field equipment.

Thus, reinjection of gases will solve numerous problems in a geothermal field operation but may also generate a number of new problems:

1. Handling of the gases in a given set of field operations is difficult and may vary with the lifetime of the field (see above).

2. Reinjection of gases and handling of gases in the surfaces equipment can not be separated and must be considered an integral part of the entire field operation.

3. Reinjection of a pure gas phase into the reservoir may eventually cause gas channeling between injection and production wells thus generating a new set of reservoir management problems.

Some of the possible solutions of the problems of a successful gas handling and reinjection are discussed in Section 8.2.3 (see also References [18,107].

### 7.2.3 PROBLEMS RELATED TO WELL AND RESERVOIR INJECTIVITY

In this section we will discuss the problems of injectivity as opposed to injectability (see previous section). It seems to be rather difficult to clearly separate between injectability and injectivity problems because both are interrelated. Injectability and injectivity are like cause and effect. If the injectability of an injection (or reinjection) brine is "poor", the injectivity of the formation can decrease as the injection operation proceeds. In other words, as the volume of the brine injected increases, it could reduce the injectivity of the formation through various damaging materials (see Section 7.1, 7.2.1 and 7.2.2). Unlike the injectability, the injectivity of a formation (or a well) can be defined through measurable parameters (see equation 2 of Section 7.1). It should be emphasized here that the injectivity is calculated and/or monitored through two parameters (injection rate and injection pressure) measured during actual field operations. A constant monitoring of the injectivity during field operations will aid the geothermal operator in assessing any injectivity impairment. All the sources of injectability problems discussed in this report can directly affect the injectivity of the formation. An awareness of these various sources of problems in conjunction with the monitoring of injectivity and proper conventional well tests to determine the location (and possibly the nature) of damage can help in minimizing and/or repairing the injection problems. Basically, if the injectability of an injected fluid does not cause a deterioration of the injectivity with time, one can safely assume that neither injectability nor injectivity problems exist. However, many geothermal injection wells operated in a porous medium reservoir have shown some decline of the injectivity with time.

Even though the injectivity of the reservoir is quantitatively defined, the effect of injectability on the injectivity is not well-defined and cannot be predicted definitely. These are too many sources in a complex geothermal operation which can alter the injectivity. None of these sources is amenable for a quantitative determination of their effects on injectivity. Barkman and Davidson [114] devised a rather ingeneous way to predict injection problems caused by suspended particles. Even this method (which accounts for only the effect of suspended particles on injectivity) is not without problems. The various problems of using Barkman and Davidson's method in geothermal operations (especially the reinjected brines) have been fully discussed in an earlier report [1]. A comprehensive study conducted by VR on the flow of particle suspensions through porous media showed the complexity of the problem [19]. At the present time, there is no method which can predict the injectivity quantitatively taking into account all the potential sources of well and/or reservoir damage. Some of the alternate ways to avoid this problem through field monitoring, well-testing and through minimizing the potential sources of damage are discussed in Section 8.0.

### 7.2.4 DAMAGE OF WELLS AND RESERVOIR RELATED TO REINJECTION AND INJECTION

All injectivity and injectability problems mentioned in the previous sections can easily lead to a damage of the reinjection (or injection) wells and reservoirs if these problems are not avoided or solved in due time. The moment an operator recognizes any damage to his wells or reservoir, he must at once determine the cause and take appropriate counter measures. This procedure generates a new set of problems:

1. How can one determine the downhole problems after the fact has occured? A considerable number of direct causes may have lead to the damage. It is also probable that more than one direct cause or even synergistic effects have lead to the damage.

2. It is required to recognize the damage at the earliest possible time to avoid any deepening or worsening of the damage effects through continuous operations. Quite often, the relation between plugging of the reservoir and the associated decrease of the injectivity is not directly and linearily related to the volume (or mass) of the injected fluid but is governed by exponential relationships. Thus, waiting too long before counter measures are taken will frequently result in the actual loss of the injection well. The damage may have progressed too far to warrant a successful repair or stimulation. Quite a few damages can not be removed to a full restoration of the original injectivity.

It becomes obvious that the operator of a geothermal reinjection or injection system is confronted with three major sets of problems as far as well and reservoir damage is concerned:

1. He must recognize the damage at the earliest possible time and must not allow the conditions leading to the damage to continue for any length of time.

2. He must recognize the source and/or reasons for this damage, quite often, after occurrence of the fact.

3. He must design a new operational system or scheme which, hopefully, will prevent:

    a) The reoccurance of the previously encountered damage,

b) The occurance of any new type of damage.

These problems may sound rather trivial. However, not being able to handle these problems has lead to quite a few lost injection wells within the United States and, with that, to a considerable financial loss to some geothermal operators. It seems that the industry becomes more and more aware of these problems and starts to proceed rather cautiously when it comes to reinjection and injection operations.

### 7.2.5 TESTING FOR INJECTABILITY AND INJECTIVITY

Testing for the injectability and injectivity characteristics in a geothermal operation is accompanied by a rather large set of problems [4 through 9,12,13,14,17,28,29,38]. The operator must base major decisions regarding the future worth of his geothermal prospect on numerous types of information to be extracted from various types of test work. This test work begins immediately after drilling of the first well. The major test objectives are listed in Tables 9 through 14.

Presently, there seems to exist a great confusion as to what type of test methods and procedures should be utilized in order to fulfill the major test objectives listed in Tables 9 through 14. The above mentioned references deal in great detail with these test problems [4 through 9,12,13,14,17,28,29,38]. At this time we would like to point out only those test problems which are directly related to the injectability of the reinjected and injected fluids as well as the injectivity of the wells and reservoirs.

#### 7.2.5.1 INJECTABILITY TEST WORK

The injectability of brines and the associated problems are described in Section 7.2.1. The injectability of a given brine depends not only upon the various characteristics of the overall geothermal field operations (see Section 7.2.1) but also on the characteristics of the reinjection or injection reservoir and its fluids. There is no prior way of describing the injectability for a given site-specific situation other than performing laboratory tests and computer simulation studies prior to long-term testing or to starting of routine field operations. The different ways of handling these tests are described in Section 8.0.

#### 7.2.5.2 INJECTIVITY TEST WORK

As mentioned in Section 7.2.3, the injectivity is quantitatively defined and is a measurable parameter. However, prediction of injectability losses as the injection operation proceeds prior to complex test work is readily not available. The impact of suspended solids in the injection fluid and its impact on the lifetime prediction was discussed by Barkman and Davidson [114] through filter tests. However, this method has severe drawbacks while applying to the situation found in geothermal injection operation [1]. Moreover, this method does not take into account the other sources of formation damage (see Section 7.1). The best method to follow is through a constant monitoring of injectivity during geothermal operations and assessing the damage through various well testing procedures as described in Section 8.0.

### 7.2.6 PROBLEMS RELATED TO STIMULATION OF INJECTION WELLS

Geothermal injection wells are prone for (a) having a naturally low injectivity and/or (b) exhibiting serious injectivity losses at various stages of their life. This is especially true in the case of high temperature geothermal operations. The main reasons for the, sometimes, rapid injectivity losses are (a) the need to inject very large amounts of brine per well and (b) the plugging of originally good injectors due to the specific conditions of a geothermal operation have been outlined earlier. In principle, the nature of the plugging material causing the damage to the injection wells can be determined:

1. If all the fluids entering the formation are properly characterized.

2. If all the various components of the reservoir materials are known.

3. If all the physical and chemical reactions among these various components are known at different conditions of the reinjection operation.

Normally, the operator lacks this information in its entirety. No matter what type of source causes the damage, many injection wells will have to be stimulated. Basically, there are two types of stimulation methods:

a) Hydraulic fracturing with or without the aid of chemicals,

b) Chemical stimulation.

The problems associated with these two basic types of stimulation are quite different and are described below.

#### 7.2.6.1 HYDRAULIC FRACTURING

Fracture stimulation of production wells [115,116] seem to have a rather limited potential. The same stimulation method utilized in injection or reinjection wells have a much smaller potential, if any at all, to be a viable solution to some reinjection and injection problems. Even if a hydraulic fracture is properly created and propagated through a damaged zone, the main purpose of the stimulation job is defeated. Any stimulation job has the main purpose of restoring or incresing the original injectivity without changing the field geometry. A fracture leaving the injection well and approaching any of the production wells can create numerous and major problems related to the reservoir management and the long-term exploitation of the entire source. For example, the break-through of relatively cold injection fluid in any of the production wells of an entire field. Furthermore, creating of a fracture without eliminating the source for the damage (which may have generated the need for fracturing in the first place) will increase all problems, thus offering no viable solution. After a short-term increase of the injectivity, the damage will reoccur, however, this time further away from the wellbore. Thus, any futher stimulation job is now confronted with the problem to repair a damage within the reservoir at a large distance from the injector wellbore. Chemical stimulation jobs (see below) can not be applied to remove these "far-out" damage collars because of the large masses of chemicals used for such a new stimulation job.

#### 7.2.6.2 CHEMICAL STIMULATION

One of the more promising stimulation methods is through the use of chemicals. Such a stimulation method is called chemical stimulation.

A properly selected stimulation fluid will chemically or physically remove a damaging material without harming the rock matrix. Unfortunately, very few stimulation fluids, if any, can be used without harming this remaining rock matrix. These secondary damages are the main problem related to the stimulation of geothermal injection wells. A geothermal operator should be familiar with the various types of secondary damages caused by the commonly used stimulation fluids. Some of the reactions causing these secondary reactions are as follows:

1. The reaction products from the chemical reactions between stimulation fluids and damaging materials are rather insoluble and form new plugging materials.

2. The stimulation fluids may also react with the native rock materials and lead to unwanted chemical reactions. Some of the sources of unwanted reactions are as follows:

    a) The cementing materials of the reservoir rock matrix (e.g. clays or calcite) may be partially dissolved and dislodged, thus causing the migration of moveable fines and, in the worst case, matrix collapse.

b) The reaction products may be insoluble thus causing an additional plugging by secondary deposits within the formerly open pore space.

3. The stimulation fluids and/or the reaction products from the (a) fluid/damaging material and (b) fluid/rock material interactions may chemically react with the reservoir fluids, thus leading to a new type of damage.

4. The stimulation fluids themselves may be chemically incompatable with the reservoir fluids, thus again leading to a new type of damage.

All these types of seconday damages have been observed in field and laboratory experiments. Unfortunately, very little attention is paid by the operators to these secondary damages, which quite often, can be more detrimental to the injectivity than the original damage. Thus it is imperative that a stimulation job design must consider the potential for forming a secondary damage.

Three types of stimulation fluids have potential to be useful in geothermal injector stimulations. These stimulation fluids are:

1. High pH stimulation fluids,

2. Neutral pH stimulation fluids,

3. Low pH stimulation fluids or acids.

Prior to the use of any of these fluids, an operator should familiarize himself with the "problems" associated with using them. The origin for these problems are briefly reviewed here. The details on various stimulation operations can be found in various reports and publications [23,100,108 through 114].

#### 7.2.6.1 UTILIZATION OF HIGH pH STIMULATION FLUIDS

To utilize a high pH fluid for geothermal injection wells presents a luring temptation for an operator. The solid silica, one of the major sources for injection well plugging, is highly soluble in many high pH fluids. Also, some rock materials are chemically not attacked by these fluids, thus eliminating the danger of generating a rock matrix problem. Unfortunately, the native reservoir fluids as well as the injected brine is often highly sensitive to a high pH value. Not the high brine TDS, as frequently assumed, but the high concentration of divalent and trivalent ions in the brines will cause a major secondary problem. The precipitation of hydroxide and basic carbonate scales is the consequence of the chemical reactions between high pH stimulation fluids and reservoir or injection brine. These deposits and scales, particularly the hydroxides (e.g., iron, magnesium, manganese, etc.) are extremely fluffy and voluminous in the pores even if their amounts per mass or volume unit of injected fluid are only very small. Thus prior to the utilization of such fluids, a geothermal operator should evaluate the secondary problems associated with them.

#### 7.2.6.2.2 UTILIZATION OF NEUTRAL pH STIMULATION FLUIDS

Stimulation fluids having a neutral pH may also have a potential for injection well stimulations without generating a severe secondary damage. However, these fluids are also not without problems.

There are some neutral pH fluids which could be excellent solvents for certain types of damaging materials. For example, EDTA (e.g., Versene 100) and nitrilotriacetic acid salts are excellent chelating agents for the ions of the alkaline earth metals. Thus, $CaSO_4$, $SrSO_4$ and $BaSO_4$ scales could be removed by dissolving of these materials in neutral or near neutral pH water without causing secondary precipitates if properly applied. The major problem is cost. These materials are rather expensive (e.g., on a "per pound" basis) and rather large amounts would have to be used for most stimulation jobs.

These chelating agents and a number of other complexing agents could find their application in a few rare cases. It may be still more economical to use these agents instead of continuously operating a damaged injection well or drilling of a new injection well.

#### 7.2.6.2.3 UTILIZATION OF LOW pH STIMULATION FLUIDS (ACID)

Low pH or acid stimulation is probably the potentially best method of repairing or stimulating of a damaged well. Basically, there are two mechanisms by which an acid stimulation can work:

1. Removal of solid flow obstructions (damage material) from the wellbore or from the reservoir in the vicinity of the wellbore.

2. Dissolving of portions of the reservoir rock, thus creating new flow channels through the damaged portion of the reservoir by leaving the original damage material as a new "rock matrix".

Both mechanisms or any combinations of these mechanisms could lead to a successful stimulation of a geothermal injection well.

Acidizing of injection wells consists of removing the flow obstructions created by one of the mechanisms described in earlier sections. The main categories of materials that can cause damage to geothermal injection wells consist of the following:

1. Sepiolite or other clays,

2. Silica and silicates,

3. Iron compounds (iron hydroxide or iron hydroxychloride),

4. Sulfates of calcium, barium and strontium,

5. The chemicals and degradation products of various additives in drilling muds and injection waters.

6. Materials specific to a given geothermal operation (e.g., chemicals or chemical reaction products resulting from faulty operations).

Thus, acidizing an injection well involves the selection of acids or acid mixtures which remove these damaging materials without causing problems by secondary deposits of the acid reactions. Among the damaging materials listed above, sepiolite or other clays, silicates and others are directly amenable to acidizing. Some other damaging materials may require special chemical methods [23].

As mentioned above, the literature on acidizing of low temperature petroleum wells is voluminous and has been reviewed [100]. The only paper describing the negative high temperature aspects of acidizing (maximum temperature of 400 F) was prepared by Dill and Keeney [113].

From the various literature citations, it can be recognized that four major types of acids are used in conventional well treatments. These acids are:

1. Hydrofluoric acid.

2. Hydrochloric acid.

3. Formic acid.

4. Acetic acid.

5. Mixtures of the above four acids.

Depending upon (1) the type of damage, (2) the nature of the formation material and (3) the temperature, pressure and the composition of the formation fluid, the appropriate stimulation fluids should be selected. The importance of choosing the stimulation fluids which do not have any secondary reactions causing further damage cannot be over emphasized. This is a specific problem requiring site-specific studies. No ready made solutions are available for the stimulation of high temperature geothermal wells. Some solutions to these various problems and some suggestions of selecting the appropriate stimulation methods are described in Section 8.0.

## 8.0 SUGGESTIONS AND RECOMMENDATIONS TO OVERCOME REINJECTION AND INJECTION PROBLEMS

Up to this point an attempt has been made to outline the numerous problems to be expected during the development and various exploitation phases of a geothermal resource. In the following sections of this report, an attempt will be made to suggest and/or propose some solutions to these problems.

As indicated in Section 7.0, every stage of a geothermal operation can result in injection and reinjection problems. Therefore, solutions must be found (a) either to solve the problems at each stage separately or (b) through an integrated approach of solving the problems that occur at various stages of a geothermal field development and operation. As the drilling and completion stage of a geothermal prospect is independent of the rest of the field operation, solutions must be found for the problems that occur during these operations. Therefore, some of the precautions to be taken during this stage of overall field operations are given in Section 8.1. For the production, utilization and injection aspects of the geothermal operation, an integrated approach to handle the various problems is described in Section 8.2. In addition, the solutions to handle various sources of injection problems are described in Section 8.3.

### 8.1 VARIOUS PRECAUTIONS TO BE TAKEN TO MINIMIZE DAMAGE DURING DRILLING AND COMPLETION

The basic information provided in section 7.1.1 can serve as a guideline in designing a "trouble-free" drilling operation more realistically. Damage during drilling operations can be minimized thereby recovering the initial injectivity of the well. One obvious way of preventing drilling damage is through the use of "particle-free" clear brines [96] which are compatable in every respect with the formation and the formation fluids. This is not that simple and much development work is needed in this regard. Another method is to reduce the differential pressure in order to minimize drilling mud invasion. This again requires some development work on drilling techniques. Still another way (a possible way) is by back-flowing sufficient quantities of reservoir fluid immediately upon drilling and completion of a well to remove any invaded material. In addition to these, several other precautionary methods can be utilized to minimize the drilling damage. They are as follows:

1. In cases such as exploratory drilling, where the nature of the reservoir materials is not known, proper drilling

fluids can not be designed because of lack of information. The first well should be tested as soon as possible before drilling additional wells.

2. Select the liquid components of the drilling mud formulation so that they are chemically compatable with the reservoir materials. If no such source water is available, use chemically incompatable waters only after a proper chemical treatment prior to injecting these fluids into the wellbore.

3. Select the solid additives so that they do not form adverse reaction products at high temperatures. Insist upon performance charts of additives at high temperature.

4. The selected chemical inhibitors should not form adverse by-products at high temperatures (pseudo scales [97,98]).

5. Select suitable clay stabilizers so that the formation clays do not disaggregate [99,100].

6. Avoid the use of high pH drilling fluids wherever possible.

7. Avoid using excessive amounts of carbonates and bicarbonates in geothermal drilling muds.

8. In case the high temperature behavior of a geothermal drilling fluid is not known, avoid utilizing these fluids prior to the proper testing of these fluids.

9. Back-flow every injection or reinjection well to clean out drilling and completion fluids before injecting into the well.

## 8.2 AN INTEGRATED APPROACH TO SOLVE INJECTION PROBLEMS

As mentioned in Section 7.0, the reinjection and injection operations must be considered an integral part of any geothermal field operation. An illustration of this integrated approach is described in Section 6.2 [3].

The fluids (liquids and/or gases) to be reinjected or injected must be known in considerable detail at the very earliest stages of any injection operation. The critical fluid parameters must be determined in a complex and rather sophisticated field test procedures [3,9,13,14]. The main injection and reinjection problems at this early stage of the field development are related to the fluid injectability. This means that the field operator must determine the fluid injectability almost at once. Unfortunately, the fluid injectability is only governed by the characteristics of the geothermal fluids in the producing and injection (reinjection) reservoir but also by the fluid utilization processes. These fluid utilization processes can be rather complex (see Section 6.1 and reference [3]) and any damage may have a severe impact on the fluid injectability. Therefore, comprehensive test work must be performed as soon as possible to determine the fluid injectability as a function of all conceivable fluid utilization conditions. The thermodynamics, kinetics and hydrodynamics affecting the fluid injectability must be studied and determined with all required detail [1,3] through early field test work [9,13,14].

Basically, the following variables must be determined:

1. Size, size distribution, concentration and type of suspended particles under all utilization conditions.

2. Chemistry of all produced fluids under various utilization conditions and their interactions with all materials that exist in the injection (reinjection) reservoir.

Many of the facilities and procedures utilized in these field experiments were described in previous reports and publications [13,].

## 8.3 LIQUID AND GAS REINJECTION AND INJECTION

The sources of problems associated with injecting fluids into geothermal wells and the effect of these problems on the injectivity of the formation (and wells) were discussed in Section 7.0. In the various sections, the difficulties associated with quantifying the injectability of a brine and the injectivity alterations as the injection operations proceed have been pointed out. As such, no universal methods exist to solve these problems. However, certain guidelines can be suggested which can be incorporated into any injection program of a geothermal operation. These guidelines should be incorporated into any future or on-going injection program of a geothermal operation. These guidelines are described in this section. They are described (1) in the form of possible or probable solutions, (2) as test procedures to assess the problems, (3) as treatment methods and (4) as monitoring procedures for proper quality control.

### 8.3.1 WELL TESTING

A properly designed and conducted well test operation can provide site-specific solutions to some of the problems described in Section 7.0 [9,13,14]. Of course, the general objectives of any geothermal well-testing are much broader than just solving injection problems (see Table 10 through 15). A prospective geothermal well and injection well should be subjected to well-testing prior to any long-range development and utilization of geothermal resources. From the point of view of solving the injection and reinjection operations, this well-testing should accomplish the gathering of the following information:

1. An integrated aproach to geothermal well testing should be pursued on any newly developed geothermal sites to gather information about various aspects of the geothermal operation including the injection and reinjection operations.

2. In order to save cost and, at the same time, to speed up the costly development of a geothermal resource, integrated well testing should be performed to determine not only critical reinjection variables but also (simultaneously) the critical production and utilization features.

3. The integrated well testing should be performed in such a way that precise data on all the properties of the geothermal source is obtained which can directly effect the injection and reinjection operations.

4. The well testing should be accompanied by full-scale experiments related to brine treatment processes. The well testing should also provide design characteristics for geothermal brine treatment facilities.

5. The test facilities should be designed and operated in such a way that minimum damage occurs to the injection wells.

6. During the well testing, all variables leading to the plugging of an injection well by suspended particles must be investigated and controlled to avoid damage of injection wells. During this stage all the information needed for a brine treatment facility suitable for power plant operation should be gathered.

7. The well testing facility should be able to determine the thermodynamics of non-condensable gaseous emissions so that future gaseous vent operations and associated gas reinjection processes can be designed.

### 8.3.2 REMOVAL OF SUSPENDED SOLIDS

The heat-depleted brine should be treated properly prior to its reinjection. The various problems associated with reinjection have been described in Section 7.2.1. Some of the solutions to overcome these problems are described in this section. As pointed out in Section 7.2.1.1, the suspended solids are the main sources of the damage which causes an injectivity decline. Therefore, it is imperative that the heat-depleted brine be treated to remove all the suspended solids (see Section 7.2.1.2.1). These suspended solids include:

1. The suspended solids brought from the producing reservoir.

2. The suspended solids generated by precipitation (e.g., silica, calcium carbonate, hydroxides, etc.).

Some of these treatment methods are described in this section and should serve as guidelines in selecting brine treatment methods. Here again, no universally accepted procedures (cook-book type methods) can be given. Only some potential methods that can offer solutions can be suggested here. It should be emphasized here that these methods be tested at site-specific locations prior to their incorporation into the design of facilities for power generation.

8.3.2.1 <u>SUSPENDED SOLIDS UNDER RESERVOIR CONDITIONS</u>

Some suspended solids can originate from the production reservoir [9]. This includes the production of formation sand and other fines. It is a very site-specific problem. Any such productin of fines can cause severe errosion to the various components of any system unless proper precautions are taken. The solutions to these reservoir solids production include the following:

1. The wells should be properly completed to keep the sand from entering the wellbore. In other words, the completed wells should be mechanically sound through a proper liner design.

2. A liner or casing, which can help to keep the formation solids from entering the wellbore may be slotted, wire wrapped (screens) or perforated.

3. The surface equipment should properly be designed to mechanically handle the sand if the downhole techniques are not adequate. However, it should be realized that this is a site-specific problem and may not occur in every geothermal well.

8.3.2.2 <u>SUSPENDED SOLIDS FORMED BY PRECIPITATION</u>

The heat-depleted geothermal brines have a potential to precipitate a maze of various compounds in the form of suspended solids. The dominating components in these suspended solids generally are metal oxides, hydroxides, carbonates, sulfates, and sulfides. The nature of the actual chemical compounds formed, their size and quantity depends not only upon the specific reservoir brine but also upon the operating parameters of the brine utilization and treatment facilities. Thus site-specific methods should be used to remove the suspended solids. The operational efficiencies of these facilities should be monitored for a proper quality control of the injected brine. The operation of a specific type of brine treatment facility under a variety of operating conditions were tested in three different geothermal well-tests [4,13,14,32]. The effect of the operational parameters on the efficiencies of the various components of the brine treatment facilities were studied during field experiments [12,37]. As a guideline for removing the suspended particles, the following suggestions are made:

1. Some laboratory flow tests should be done to determine the "level" to which the suspended solids need to be removed prior to injection. This should be done using representative core samples from the field using suspended particles of various sizes.

2. Utilize a combination of reactor/clarifier and a sandbed filter system to render the fluids "injectable". In other words, the brine treatment facility should be able to remove to the level set by the laboratory studies.

3. The brine clarification system should be tested to optimize the operating parameters of the various components of the system. This should be done in the field during well performance testing through particle measurements at the inlet and outlet of each of the components of the system.

4. During the actual injection operations, proper particle monitoring should be constantly done to assume the proper operation of the clarification system. A warning system connected to the particle monitoring system should be utilized to assure proper quality control of the injected fluids. This warning system should also provide a means to direct the fluids away from the injection well in case of an unusually high suspended solids content occurs within the fluid.

5. Disposal of the separated solids may become a major environmental problem. Unless a proper disposal method is found, the entire operation of such a field has not future within the United States.

6. The most ideal way is to sell the separated solids thus converting them from a liability to an asset. However,

this means that these solids can not contain materials which generate an environmental, technical or financial liability to the purchaser.

7. In order to render these separated solids sellable, or at least, safely disposable one must keep in mind that the fluid production and utilization processes can have a sever impact upon the composition of these solids. This may require compromises between production, utilization and reinjection operations. For example, a flash-crystallizer may solve some scale problems but may render the solids separated upstream of the reinjection wells non-sellable and impossible to dispose of in a technically and feasible manner.

### 8.3.2.3 ADDITIVES USED IN REINJECTED BRINES

Many chemical additives are added to the geothermal fluids prior to their reinjection. Among the various chemicals used, the organic flocculants and inhibitors are the most common ones. As mentioned in an earlier report [25,75] these chemicals can degrade and cause near wellbore damage. Thus a cautious approach should be taken in using them. These include the following:

1. Before utilizing specific flocculants (or other chemicals) in a given geothermal operation, they should be tested through core flow tests in the laboratory prior to their use in the field. This should be done by using representative core plugs.

2. The optimum quantity of chemical additives needed should be determined to avoid excess amounts entering the reservoir. This will not only save cost but will also prevent well and reservoir damages through over treatment.

3. Effective analytical methods (preferably rapid or on-line methods) should be developed to determine low concentrations of these chemicals. This will help to properly monitor the brines for the presence of "excess" concentrations of chemicals prior to their entrance into the injection wells.

### 8.3.3 GAS TREATMENT

The following guidelines can be suggested to handle the problems associated with gases emitted from geothermal operations:

1. In order to decide the way of handling the non-condensable gases, the chemical nature and quantity of each of the gases emitted under various field and

power plant operating conditions should be determined at the earliest possible time. This, in turn, would require the correct determination of the brine composition under downhole conditions.

2. The composition of the brine under downhole conditions need to be determined with sufficient accuracy (i.e., "sufficient" for the calculation of gaseous emissions) so that proper processes and procedures for handling the non-condensable gases can be developed. The determination of the brine composition under downhole conditions can be done by mathematically recombining the chemical compositions of the liquid and vapor phases sampled and analyzed at the surface conditions. The method relies on accurate determinations of the flow rates of the two fluid phases, proper sampling of the liquid and the vapor phases for chemical analysis and accurately measuring the constituents of the samples collected.

3. In order to determine the redistribution of the various species of the dissolved gases at the temperature and pressure of the bottom of the well, the different reactions among the various dissolved gases and water will have to be considered using thermodynamic principles. This type of information is particularly needed for scale prediction.

4. The geothermal brines under reservoir conditions normally show a fairly low pH. The heat-depleted brines which are stripped of their dissolved gases have a fairly high pH value. The impact of injecting high pH fluid back into a specific reservoir should be invesstigated through (a) laboratory experiments and (b) thermodynamic fluid modeling.

5. Based upon the information (see above) gathered at the earliest possible time, the decision has to be made whether to (a) reinject or (b) sell or (c) dispose of the stripped gases.

6. If the reinjection of non-condensable gases is planned, the technical and economic feasibility of reinjecting the gases must be investigated at the earliest possible time.

7. The potential saleability of CO2 emitted from a specific geothermal field should be studied.

8. Environmental considerations may limit the disposal of the gases into the atmosphere. One should expect a future tightening of environmental rules and regulations and, therefore, should plan on a proper gas handling as

early as possible.

9. The economics of gas treatment processes (e.g., for $H_2S$ abatement) versus gas reinjection should be evaluated as early as possible. Future retrofitting of the field installation to switch from one process to another may become prohibitively expensive.

### 8.3.4 INJECTION OF FOREIGN OR IMPORTED BRINES

As described in Section 7.2.1.1.3 and elsewhere [11,20], any type of "foreign" injection water could result in additional scale problems (e.g.,sulfate scales). Thus, preventive measures must be taken to avoid this damage before it actually occurs. The various possibilities to deal with these precipitation and scale problems are as follows:

1. Removal of sulfate ions from the foreign waters prior to injection to a residual level which eliminates the potential for sulfate precipitation.

2. The major scale problem caused by the injection of foreign waters is expected to occur within or near the production wells and not in the vicinity of the injection wells.

3. Injection of chemically compatable waters prior to injecting chemically incompatable waters. This "prepad" may not only cool the reservoir (thus reducing the formation of scale) but will also cause a dilution of the chemically incompatable waters, thus further reducing the scale formation.

4. Addition of scale inhibitors to the foreign waters prior to injection to prevent the formation of solids close to the reservoir regions around the injection wells. However, this would only solve the scale problems in the vicinity of the injection wells but not the problems to be encountered in the production wells and surface facilities upstream of the power plants.

5. Scale inhibitor squeezes into the production wells to avoid the formation of skins in or close to the production wells.

6. Continuous injection of scale inhibitors into the production wells (e.g. via a macaroni string) to avoid the formation of scale within the wellbores of the production wells and the surface equipment.

#### 8.3.4.1 SULFATE ION REMOVAL FROM INJECTION WATER

If the detrimental SO4-- ions content could be removed from the "foreign" injection water prior to its injection into geothermal reservoir, no serious problems would exist in the field as far as the sulfate scale formation is concerned. The question now arises: To what level should the sulfate concentration be reduced to prevent or reduce the sulfate scale formation? This question cannot be answered in a general manner. The answer to this question is specific to a given geothermal operation.

The principal recommendations for the planning of any injection operation using "foreign" waters in geothermal applications are as follows:

1. Prior to any injection of imported water into a geothermal reservior, the chemical compatability of the injection water and the reservoir water should be studied through computer modeling and laboratory studies [11,20].

2. The degree of sulfate deionization required for the prevention or reduction of the scale at various locations for each geothermal operation should be thoroughly studied through computer modeling.

3. The economics of using sulfate deionization alone, or of using scale inhibitors alone or using a combination of both should be thoroughly studied prior to any injection of imported waters. Otherwise, severe damage to the reservoir near the injection wells and within the production wells can be expected.

#### 8.3.4.2 USE OF SCALE INHIBITORS

The utilization of scale inhibitors is one of the most common methods of combating the scale problems in oil and gas field operations involving incompatable water mixing. The extension of the scale inhibition technique to geothermal operations is not easy mainly because of the high temperatures and high salinity of the brines. No information is available in the literature that can be used in selecting inhibitors for application to geothermal operations involving incompatable water mixing. A limited amount of information has been compiled by VR as part of the present contract [16] and it serves only as a basis for the selection of inhibitors.

Any geothermal operator pursuing the injection of foreign waters should consider the following recommendation:

1. Prior to the injection of a specific geothermal water,

some of the adequate inhibitors and/or inhibitor mixtures should be tested for their efficiencies using the actual brines from the field. This testing must be done at the temperatures encountered in the reservoir. Any additional and promising inhibitors should also be tested. These lab testings should preceed any field test to avoid any secondary problems due to the application of the inhibitors.

2. Specific attention should be given to the presence of poisoning elements in the brines. One of the poisoning elements are iron ions. Other elements in the iron group may also act as poinsoning elements against inhibitors.

3. The compatibility of the inhibitors with the brine in question should be tested at reservoir temperatures to determine any side effects before they are used in the field.

4. In addition, the cost and effectiveness of using inhibitors versus the brine treatment to remove "excessive" SO4-- should be studied.

### 8.3.5 WELL AND RESERVOIR STIMULATION

As pointed out in Section 7.0, well stimulation through chemicals is eventually needed to repair the damage to injection wells. Following are some of the guidelines to be followed in well and reservoir stimulation operations.

1. Prior to any acidizing design for the stimulation of injection wells, the nature, location and amount of the damage causing material and the location of the damage itself should be determined as much as possible. This may sound trival but is hardly ever done in the field. A concrete proof for the nature, location and/or amount of damaging material is very difficult to gather in the field. This lack of information may require the need for experimental or pilot jobs prior to performing routine stimulation jobs in a given field under a given set of conditions.

2. Laboratory tests to study the reactions involving the actual rock material in the vicinity of the injection well and the potential acids should be done prior to performing an acid job. This should be done preferably at the bottomhole temperature of the injection well to determine if any secondary and damaging reactions occur between the acid and the formation or flow restricting material.

3. Procedures should be developed for a clean-up of the well after acidizing to remove any unreacted acids, chemical additives and any loose fines. Forcing the reaction products from the vicinity of the well into the reservoir may or may not lead to severe damage collars further away from the wellbore.

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## TABLE 1

## REASONS FOR REINJECTION OF HEAT-DEPLETED BRINE AND INJECTION OF IMPORTED BRINES

I. REINJECTION OF HEAT-DEPLETED BRINES

1. DISPOSAL FOR ENVIRONMENTAL PURPOSES.

2. PRESSURE MAINTENANCE AND PREVENTION OF SUBSIDENCE.

3. ENHANCED HEAT RECOVERY.

II. INJECTION OF IMPORTED WATER

1. MAKE-UP WATER TO PREVENT SUBSIDENCE AND TO COMPLY WITH OTHER LEGAL OR ENVIRONMENTAL REGULATIONS.

2. PRESSURE MAINTENANCE AND ADVANCED HEAT-MINING.

3. WASTE WATER DISPOSAL (AQUEOUS WASTES GENERATED DURING VARIOUS OPERATIONS.

## TABLE 2

### MAJOR SOURCES THAT EFFECT INJECTION OPERATIONS

1. DRILLING AND COMPLETION OF INJECTION WELLS
2. REINJECTION OF HEAT DEPLETED BRINES
3. INJECTION OF IMPORTED BRINES
4. INJECTION OF OTHER FLUIDS

## TABLE 3

### TYPES OF DAMAGES EXPECTED DURING DRILLING AND COMPLETION

1. INVASION AND PHYSICAL BLOCKING OF PORES BY DRILLING MUD PARTICLES.
2. CHANGE IN PROPERTIES OF INVADED PARTICLES BY HIGH TEMPERATURES AND SALINITY OF BRINES.
3. PRECIPITATION OF SALTS OR OTHER SOLIDS DUE TO CHEMICAL INTERACTION BETWEEN DRILLING MUD FILTRATE AND THE RESERVOIR BRINES.
4. DISAGGREGATION AND/OR SWELLING OF CLAY MINERALS THAT ARE NATIVE TO THE FORMATION DUE TO THE IONIC SPECIES FROM DRILLING MUD FILTRATE.
5. CORROSION PRODUCTS DURING DRILLING.
6. DEGRADATION OF CHEMICALS USED DURING DRILLING OPERATIONS UNDER THE CONDITIONS OF GEOTHERMAL FORMATION.

TABLE 4

VARIABLES THAT DETERMINE GEOTHERMAL BRINE INJECTABILITY

1) PHYSICAL PROPERTIES OF INJECTED FLUID

  A) PROPERTIES OF SUSPENDED PARTICLES

    (1) SIZE AND SIZE DISTRIBUTION

    (2) CONCENTRATION

    (3) SHAPE FACTORS

    (4) SURFACE PROPERTIES (SURFACE ENERGY)

    (5) SPECIFIC WEIGHT

    (6) FLOCCULATION PROPERTIES

    (7) DUCTILITY

    (8) BRITTLENESS

  B) PROPERTIES OF LIQUID PHASE

    (1) SPECIFIC WEIGHT

    (2) SURFACE TENSION

  C) PROPERTIES OF SOLID/LIQUID MIXTURE

    (1) TEMPERATURE

    (2) PRESSURE

2) CHEMICAL PROPERTIES OF INJECTED FLUID

  A) COMPOSITION

  B) CHEMICAL REACTIVITY OF ADDITIVES

TABLE 4 (CONTINUED)

3) PHYSICAL PROPERTIES OF RESERVOIR ROCK

   A) POROSITY

   B) PORE SIZE DISTRIBUTION

   C) PERMEABILITY

4) CHEMICAL PROPERTIES OF RESERVOIR ROCK

   A) CLAY SWELLABILITY

   B) CLAY DISPERSIVITY

5) PHYSICAL PROPERTIES OF RESERVOIR ROCK

6) CHEMICAL PROPERTIES OF RESERVOIR ROCK

# TABLE 5

## TYPES OF DAMAGES EXPECTED DURING REINJECTION OF HEAT-DEPLETED BRINES

1. INVASION AND PHYSICAL BLOCKING OF FORMATION PORES BY SUSPENDED PARTICLES.
2. THERMODYNAMIC INSTABILITY OF THE HEAT-DEPLETED BRINES.
3. CHEMICAL INCOMPATIBILITY BETWEEN HEAT-DEPLETED BRINES AND RESERVOIR BRINES.
4. CHEMICAL INCOMPATIBILITY BETWEEN HEAT-DEPLETED AND FORMATION MATERIALS.
5. CORROSION DUE TO OXYGEN CONTAMINATION.
6. DEGRADATION OF CHEMICALS USED DURING PRODUCTION OPERATIONS.
7. DEGRADATION OF CHEMICALS ADDED DURING INJECTION OPERATIONS.

## TABLE 6

## TYPES OF DAMAGES EXPECTED DURING INJECTION OF IMPORTED WATERS

1. INVASION AND PHYSICAL BLOCKING OF PORES BY SUSPENDED PARTICLES.

2. THERMODYNAMIC INSTABILITY OF THE IMPORTED BRINES.

3. CHEMICAL INCOMPATIBILITY BETWEEN IMPORTED BRINES AND RESERVOIR BRINES AND RESULTING SCALE PROBLEMS.

4. CHEMICAL INCOMPATIBILITY BETWEEN IMPORTED BRINES AND FORMATION CLAY MATERIALS.

5. CORROSION DUE TO OXYGEN FROM IMPORTED WATERS.

6. DEGRADATION OF CHEMICALS ADDED TO INJECTION BRINES.

## TABLE 7

## SOURCES OF SUSPENDED SOLIDS

1. PARTICLES GENERATED THROUGH PRECIPITATION REACTIONS IN THE FLOWING BRINE. (e.g., SILICA, SILICATES, HEAVY METAL SULFIDES AND CARBONATES).

2. PARTICLES NATIVE TO PRODUCING RESERVOIR AND TRANSPORTED INTO THE INJECTION SYSTEM BY THE FLOWING BRINE (e.g., SAND GRAINS AND CLAY PARTICLES).

3. PARTICLES FORMED THROUGH MIXING OF INCOMPATIBLE WATERS (e.g., ALKALINE EARTH METAL SULFATES AND CARBONATES).

4. PARTICLES GENERATED BY UNDESIRED PRECIPITATION REACTIONS CAUSED THROUGH ADDITION OF CHEMICALS TO THE BRINE (e.g., CALCIUM PHOSPHONATES AND POLYACRYLATES).

5. PARTICLES CAUSED BY VARIOUS TYPES OF CORROSION (e.g., IRON SULFIDES AND HYDROXIDES).

6. PARTICLES CAUSED BY OXYGEN CONTAMINATION (e.g., IRON HYDROXIDES AND IRON OXY-HYDRATES).

7. PARTICLES FORMED THROUGH BACTERIAL REACTIONS (e.g., SLIMES).

8. PARTICLES FORMED BY DISLODGED FORMATION MATERIAL CAUSED BY TEMPERATURE AND MECAHNICAAL STRESSES (e.g., CLAY PARTICLES).

9. PARTICLES CAUSED BY A LACK OF CLEANLINESS (e.g., DIRT AND MUD PARTICLES).

10. PARTICLES CAUSED BY LACK OR INEFFICIENCY OF CLEAN-UP AFTER DRILLING AND COMPLETION OF WELLS (e.g.,MUD FINES, FORMATION CUTTINGS AND BREAK-DOWN PRODUCTS OF DRILLING AND COMPLETION FLUIDS).

## TABLE 8

## DIFFERENT WAYS SUSPENDED PARTICLES CAN CAUSE REDUCTION IN INJECTIVITY

1. FILL-UP OF THE WELLBORE
2. FORMATION OF A FILTER CAKE ON THE SANDFACE
3. PARTICLE INVASION OF THE RESERVOIR AND FORMATION OF DAMAGE COLLARS
4. PLUGGING OF PERFORATION HOLES
5. CHANGE IN PROPERTIES OF INVADED PARTICLES BY HIGH TEMPERATURES AND HIGH SALINITY

# TABLE 9

## OBJECTIVES FOR GEOTHERMAL WELL TESTING

1. RESERVOIR CHARACTERISTICS
2. WELLBORE/RESERVOIR INTERFACE
3. WELLBORE
4. FLUID UTILIZATION
5. PROBLEMS ASSOCIATED WITH REINJECTION AND INJECTION (DISPOSAL)

## TABLE 10

### OBJECTIVES FOR GEOTHERMAL WELL TESTING (RESERVOIR CHARACTERISTICS)

1. STATIC PRESSURE, TEMPERATURE, FLUID PROPERTIES IN RESERVOIR

2. AVERAGE KH

3. STORAGE CAPACITY IN RESERVOIR ( HC)

4. RESERVOIR TYPE:

   A) FRACTURED

   B) MATRIX (UNIFORM OR HETEROGENEITIES)

   C) COMBINATION

5. BOUNDARY EFFECTS DUE TO:

   A) FAULTS

   B) PINCH-OUTS

   C) LATERAL CHANGE OF DIFFUSIVITY

   D) CLOSED OR LEAKY BOUNDARIES (INFLUX AND/OR COMMUNICATION)

6. VERTICAL TRANSMISSIBILITY

7. FLOW EFFICIENCY (STEADY STATE PRODUCTIVITY)

8. RESERVES:

   A) HEAT IN PLACE

   B) HEAT RECOVERABLE

TABLE 11

OBJECTIVES FOR GEOTHERMAL WELL TESTING
(WELLBORE/RESERVOIR INTERFACE)

1. THEORETICAL WELL PRODUCTIVITY

2. NEAR WELLBORE PRODUCTIVITY IMPAIRMENT DUE TO DRILLING

3. NEAR WELLBORE PRODUCTIVITY IMPAIRMENT DUE TO PRODUCTION:

   A) DAMAGE DUE TO FLOWING FLUID PROPERTIES (SCALE)

   B) DAMAGE DUE TO FORMATION SOLID (SAND, CLAY, ETC.,)

   C) DAMAGE CAUSED DURING STIMULATION

## TABLE 12

### OBJECTIVES FOR GEOTHERMAL WELL TESTING (WELLBORE CHARACTERISTICS)

1. PROBLEMS CAUSED BY PERFORATIONS AND/OR SLOTS
2. HARDWARE INDUCED PROBLEMS
3. FLUID INDUCED PROBLEMS
4. TEMPERATURE INDUCED PROBLEMS
5. FLOW INDUCED PROBLEMS
6. WELLBORE STORAGE EFFECTS

TABLE 13

OBJECTIVES FOR GEOTHERMAL WELL TESTING
(FLUID UTILIZATION

1. CHEMICAL AND PHYSICAL FLUID BEHAVIOR AS FUNCTION OF TEMPERATURE, PRESSURE, RATE AND TIME

2. FLUID PHASE BEHAVIOR AS FUNCTION OF TEMPERATURE PRESSURE, RATE AND TIME

3. FLOW DYNAMICS AND ASSOCIATED EFFECTS

4. SUSPENDED PARTICLES AND THEIR BEHAVIOR

5. ENVIRONMENTAL

6. ADAPTABILITY OF FLUIDS FOR CHEMICAL AND PHYSICAL ALTERATION

TABLE 14

OBJECTIVES FOR GEOTHERMAL WELL TESTING
(REINJECTION

1. WELLBORE

2. WELLBORE/RESERVOIR INTERFACE

3. RESERVOIR

# SIMPLE GEOTHERMAL OPERATION

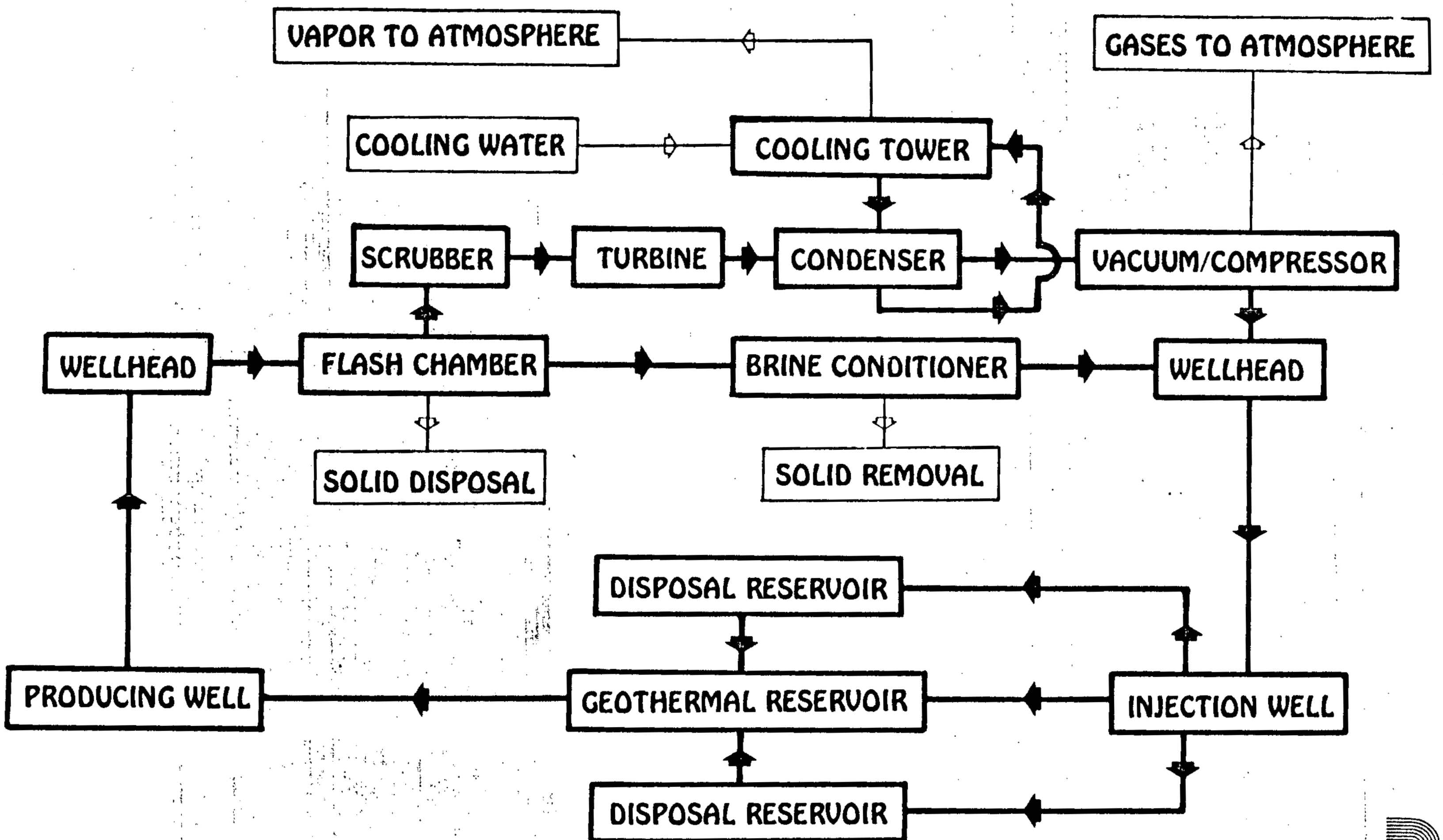


FIGURE 1

# ADVANCED GEOTHERMAL OPERATION

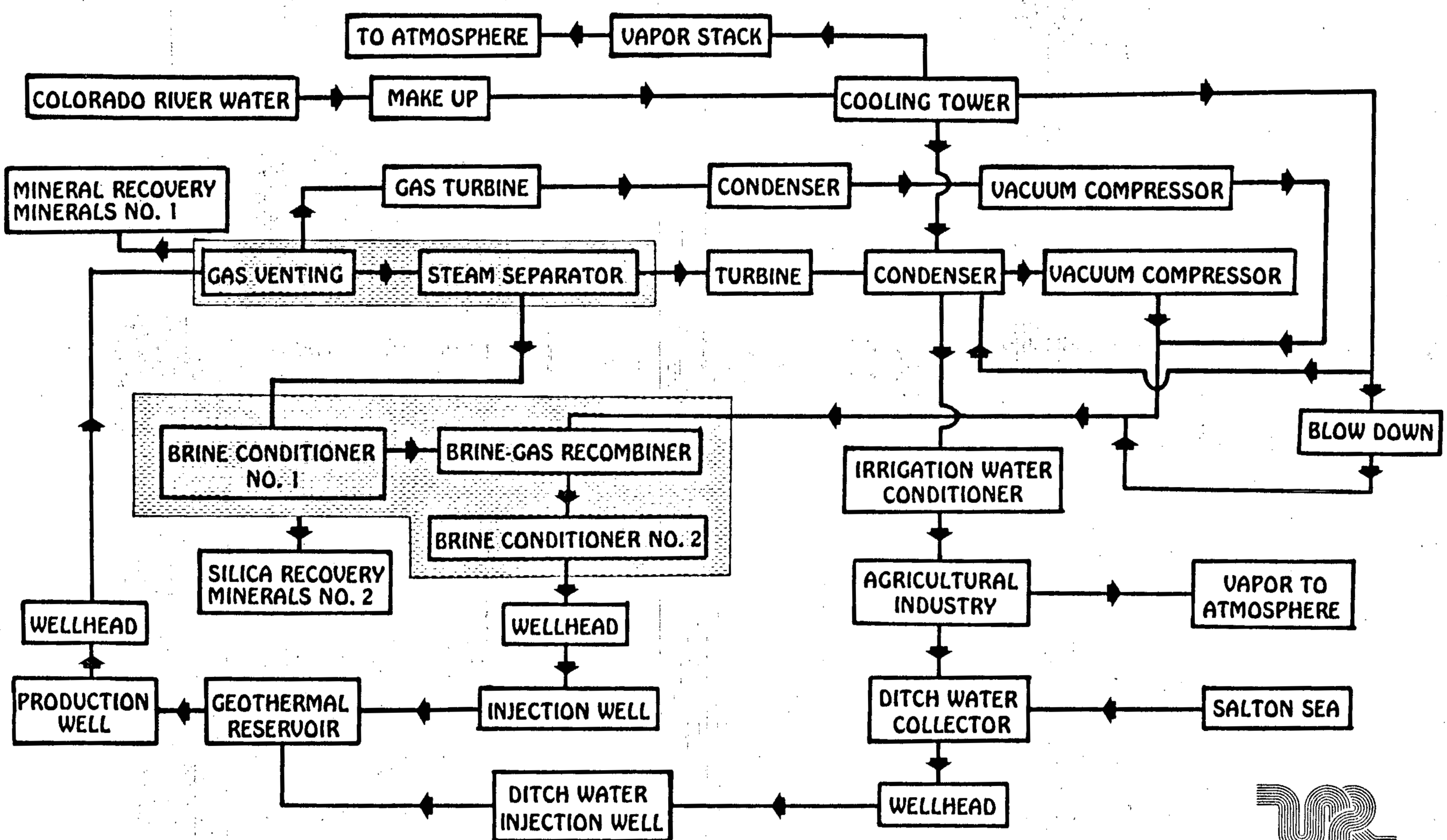


FIGURE 2

FIGURE 3

# PRECIPITATION OF SULFATES UPON HEATING OF SALTON SEA WATER (AT 406 ATM)